The Effect of Distributed Generation on Power System Protection

by

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I certify that all material in this thesis which is not my own work has been identified and that no material has previously been submitted and approved for the award of a degree by this or any other University.

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Abstract

Interconnecting a distributed generation (DG) to an existing distribution system provides various benefits to several entities such as the DG owner, utility and end users. DG provides an improved power quality, higher reliability of the distribution system and covering of peak shaves. Penetration of a DG into an existing distribution system has so many impacts on the system, despite the benefits a DG will provide; it has a negative impact on one of the most important aspects of the system which is the power system protection, and it is a main factor affecting both reliability and stability of the system. DG causes the system to lose its radial power flow, besides the increased fault level of the system caused by the DG. In this thesis, the effect of DG penetration on the short circuit level of the network is investigated through simulating the IEEE 13 bus test feeder using **ETAP.** The simulation is repeated for nine different cases at which the location of one large DG is changed in six of the cases to study the effect of the distance on the fault level, while the rest of the cases are performed using small decentralised DGs. The result of those three cases at which the DG is decentralised are used to investigate the effect of the generating capacity of the generation unit on the distribution network parameters and on the currents flowing through the laterals of the distribution network. Results are compared to that of the normal case to investigate the impact of the DG on the short circuit currents flowing through different branches of the network to deduce the effect on protective devices.

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List of Symbols and Abbreviations

DG: Distributed Generation

PV: Photovoltaic

LTC: Load Tap changer

IGBT: insulated gate bipolar transistor

PCC: point of common coupling

ACSR : Aluminium Conductor Steel Reinforced

XFM-1 : Distribution Transformer number 1 in the IEEE test feeder

AA : Aluminium Conductor

Cu : Copper conductor

NDZ: non detective zone

I_p: Pickup Current

V_{rms}: Root Mean Square of the voltage

TDS: Time Dial Setting

T: Operating Time

T_{ijk}: operation time of relay i of branch j for fault k.

T_{nmk}: operation time of the first backup of R_{ij} for a given fault in protection zone k.

I_{ijk}: the current passing through the relay R_{ij}.

T_{CBB}: time of operation of circuit breaker B

T_{CBK}: time of operation of circuit breaker K

TDSA: time dial setting of relay A

TDSB : time dial setting of relay B

TDSC: time dial setting of relay C

TDSD: time dial setting of relay D

TDSE: time dial setting of relay E

TDSF: time dial setting of relay F

TDSG: time dial setting of relay G

TDSH: time dial setting of relay H

TDSI: time dial setting of relay I

TDSJ: time dial setting of relay J

TDSK: time dial setting of relay K

TDSL: time dial setting of relay L

TBA1: time of operation of relay A for a fault in zone 1 at its close end

TBB1: time of operation of relay B for a fault in zone 1 at its close end

TBC2: time of operation of relay C for a fault in zone 2 at its close end

TBE3: time of operation of relay E for a fault in zone 3 at its close end

TBD2: time of operation of relay D for a fault in zone 2 at its close end

TBK1: time of operation of relay K for a fault in zone 1 at its close end

TBF3: time of operation of relay F for a fault in zone 3 at its close end

TBG4: time of operation of relay G for a fault in zone 4 at its close end

TBH4: time of operation of relay H for a fault in zone 4 at its close end

TBI5: time of operation of relay I for a fault in zone 5 at its close end

TBJ5: time of operation of relay J for a fault in zone 5 at its close end

IpA: the pickup setting of relay A

IpB: the pickup setting of relay B

IpC: the pickup setting of relay C

IpE: the pickup setting of relay E

IpF: the pickup setting of relay F

IpG: the pickup setting of relay G

IpH: the pickup setting of relay H

IpI: the pickup setting of relay I

IpK: the pickup setting of relay K

Chapter 1: Introduction

1.1 Brief Introduction

Among the various energy forms, electrical power plays the major role due to the fact of its ease to generate and utilise. As a result of the increasing awareness and economic concern of the consumers in the past few decades, one of their main concerns is to receive a more reliable electrical power supply with fewer expenses which caused a higher challenge to the electric utilities, as they are expected to deliver higher quality service through the reliability of the supply with less cost. In order to achieve less cost, utilities are targeting a system with less operation and maintenance costs, reduction of resources cost and reducing the system losses.

For electric utilities to deliver electric power to consumers there are several stages to be passed through, the first stage is the generation, at which electricity is generated in large sized generation stations that are located in non-populated areas away from all loads to overcome the economics of size and environmental issues. Second stage is the transmission; this is done with the aid of several equipments such as transformers, overhead transmission lines and underground cables. Transmission is an important part of the system that consumes a lot of money to transmit the generated electricity to reach the last stage which is the distribution.

Distribution system is the link between the end user and the utility system, it is the most crucial part of the power system and it is facing a lot of threats that cause a power interruption to customers, it can be stated that a great percentage of end users' power outages are due to distribution networks, it can also occur due to mal functioning of the networks protection equipment as a result of adding a Distributed Generation (DG) to increase the network's reliability. DG is an alternative small rated power generation unit added to the distribution network to cover the supply of some loads. There are different types and technologies of DG's used nowadays such as photovoltaic (PV) systems, wind turbine, micro-turbines, fuel cells and rotating machines. PV and wind turbines are examples of renewable energy consumables as they need no fossil fuel to operate, PV utilises the sun and wind turbines operate by the aid of wind.

Utilising renewable resources is one of the new trends to generate useful energy in the form of electrical power. It is the major form of energy production required in the world nowadays. There are certain aspects that have to be highlighted when talking about renewable energy such as efficiency, economics and environment. The name renewable resources is a self-explanatory expression that expresses the fact that these types of resources are never running out due to the fact that they are from sources such as the sun and the wind, the sun will never stop shining and the wind will always continue blowing. From the efficiency point of view, fossil fuel run energy generation edges the renewable resources technologies due to the fact that both mentioned resources are not available at all times, besides the low availability of cheap and efficient energy storage technologies. Efficiency of renewable energy technologies used in generating electricity is far too low with respect to the traditional fossil fuel run technologies. Environment outweighs renewable resources more than the fossil fuel as a supply to the energy generation units, this is due to the clean energy production process without any emissions or wastes due to combustion. Elimination of those emissions reduces the different pollution caused to the environment, besides the elimination of the impact on the climate. Despite the high initial cost of renewable energy stations, there will be a decreased running cost along with less maintenance when compared with the traditional stations, this is from the economics point of view but it does not mean that economics prefers renewable energy stations. There are other aspects that cause the economics to choose traditional generation till today; scientists are heading nowadays to increase the efficiency with a reduced size of the renewable energy technologies to compete with the other technologies from the economics point of view. When mentioning renewable energy, PV and wind turbines have to be considered as they are the major renewable energy technologies.

A PV system is a system consisting of large arrays that are formed of a number of solar cells which are used in converting the solar energy to electricity. Solar cells are made of semiconducting materials such as silicon used to generate electricity by the aid of photons supplied to it by the sun. Each cell consists of a positive and a negative layer to create an electric field for drifting the charges produced from the reaction of the photons with the semiconducting material, these charges are moved to the bottom of the cell and through a wire connecting the cells, the electricity produced depends on the intensity of light and the number of cells. To achieve better performance of the PV system, the array has to be kept at a perpendicular position with respect to the sun, thus some arrays are enriched with motors that allow it to track the sun seeking higher efficiency and better performance of the system. The output of photovoltaic is always in the form of DC, thus it has to be converted to AC in order to be utilised, and one of the most important components in this system is the inverter that is used in converting DC to AC, as the type of inverter used plays a great role when photo voltaic is used as a DG. The drawbacks of PV are the high initial cost required to build the system, large areas required for installing the system to achieve satisfying amount of power and the low efficiency.

Wind turbine is also one of the rapidly increasing technologies and its applications are also increasing in a vigorous manner. Wind turbines depend on the wind thus it has no emissions that are harmful to the environment; the only pollution form generated by large wind turbines is noise. Due to the economics of size, a large number of wind turbines are built in the same location and grouped together and interconnected together to medium voltage power collection systems. This group of wind turbines is now called a wind farm. Due to the presence of high speed winds in the oceans and seas, the idea of offshore wind farms came up to utilise these great wind speeds in generating electricity. Wind turbines that are used in offshore wind farms are usually larger in size than the land ones as the generating capacity of the unit depends on its size and the average speed of the wind at the location of the turbine. Wind turbines are constructed of three major parts, which are the blades (representing the rotor of a machine), generator (usually a doubly fed induction generator) and the power electronics equipment. Wind turbines and PV’s can be used as a DG that is interconnected to the utility network. From the economical point of view, the technology of wind turbines edges the PV technology when used as a DG in distribution networks due to the higher initial costs of PV systems, but on the other hand, when considering the performance point of view, PV systems could overcome the technology of wind turbines if it is not an inverter type wind turbine, as inverter based DGs have less impacts on distribution networks. Any way the penetration of a DG into an existing distribution network has a lot of impacts on the network but its advantages outweighs the drawbacks which forces the essential use of DGs.

DG can be owned by individual customers and interconnected to the utility network; it has so many advantages such increasing the reliability of the system, covering the peak shaves with consuming less power from the utility thus decreasing the electricity bill and covering the step increase of power demand. The draw backs of the DG are mainly to the network as it will cause several protection problems during the occurrence of a fault, examples of protection problems caused due to the penetration of DG in distribution network are reduction of reach, mis-coordination between protection devices and sympathetic tripping of protective devices. The previously mentioned impact on protective devices is due to the contribution of the DG to fault currents that were not included in the initial design and fault calculations of the system. On the other hand the presence of the DG causes the contribution of the utility substation to decrease during faults which has a positive impact on substation equipment life. This shows that penetration of a DG in the power network has an impact on both the short circuit currents and consequently on the existing protection scheme of the power system.

1.2 Thesis Objectives

The objective of this thesis is to investigate the impact of different configurations and penetration levels of DG on the short circuit level of the network through simulating a small system nine times with different configurations of the DG. The impact of DG on short circuit currents has a consequent effect on the protection and protection devices, studying this impact is the second objective of this thesis.

1.3 Thesis Structure

This thesis consists of five chapters and is organised as follows:

Chapter 1: Introduction and Thesis Outline

Chapter 2: Literature Review

Chapter 3: Simulation of IEEE 13 bus with Different DG Configurations

Chapter 4: Coordination of Directional Overcurrent Relays to Prevent Islanding of Distributed Generation

Chapter 5: Conclusions and Future Work

1.3.1 Outlines

Chapter 1 gives a brief introduction to the concept of distributed generations reflecting the importance of DG systems to both the utility network and premises, besides the drawbacks of DG on protective devices connected to the transmission and distribution systems.

Chapter 2 is divided into six sections; the first section is a brief introduction and a definition of DG, followed by the second section which discusses the various types of distributed generation technologies and their nature. The impacts of DG on power system grids are discussed in the third section. Section four highlightsone of the most important issues to maintain a safe operation of the DG, and this is the interconnection protection. Section five is an overview of one of the major problems that mis-protection can lead to and causes a difficulty in system restore, this phenomenon is called islanding. Finally the last section discusses the impact of DG penetration on the distribution feeder protection and the mis-protection problems arising from the interconnection of DGs.

Chapter 3 is the core of this thesis, in which a simulation is made to the IEEE 13 bus system with different DG configurations. Nine cases are illustrated in this chapter to study the effect of DG on the short circuit levels of the network at different fault locations, besides the effect of the DG configuration. The first case is the base case that all the results were compared to; it is the IEEE 13 bus system without the presence of any DG. Cases 2, 3, 4, 5 and 6 are elaborating the effect of DG location on the level of short circuit currents and this is obtained by repeating the simulation with the same size of DG but changing the location of the DG itself. These five cases are presenting the case of centralised DGs which is placing one large DG in the system, while cases 7and8 are going into the details of decentralised DGs, which is using a few DGs distributed over the network at different locations with a total sum of generating capacity equating the large centralised DG used in cases 2, 3, 4, 5 and 6. Case 9 is the last case at which the simulation is performed using small decentralised distributed generations but with a total generating capacity higher than all cases. Parameters and configurations of the simulated system are introduced at the beginning of the chapter and lastly a discussion on the results and comparisons made between different cases to elaborate the conclusions.

Chapter four introduces a conference paper entitled "**Coordination of Directional Overcurrent Relays to Prevent Islanding of Distributed Generators**" that was presented and published in the proceeding of EUROMED-ICEGES 2009 in Amman-Jordan, organized by the Hashemite University from 15-06-2009 to 17-06-2009. This paper is proposing a new technique for the coordination of the directional overcurrent relays that are used in distribution networks to prevent the unintentional islanding of a DG placed in the system during the occurrence of a fault in the system. Islanding can occur due to mis-protection. Types of islanding detection techniques are also mentioned in this paper.

Lastly, chapter 5 sums up the conclusions of this thesis and future work is proposed.

Chapter 2: Literature Review

2.1 Introduction

Distributed Generation (DG) is one of the new trends that attracted attention for the past years and its penetration in distribution networks is increasing in an enormous rate. DG is presented in the form of solar (PV), wind (wind farms) and many other forms with small scale ratings up to 10MW. DG refers to electric generators that are built to generate electricity and supplying it to customers close to their locations, it can also be interconnected to the utility grids. There are so many privileges a DG delivers to the customer, which encourages their choice to install a DG rather than constructing new distribution lines, doing so might be cost effective to some customers. DG can be used to provide electricity supply to customers during peak times, it can provide a consumer full demand allowing them to operate apart from the grid, thus it can support intentional islanding.

One of the most important issues that has to be considered to achieve a safe and effective use of DG is the interconnection of the DG to the utility grid, which is discussed later in this chapter. There are different DG technologies and impacts of distributed generations that are introduced in this chapter, besides the impact of DG on protection and the coordination of protective devices.

2.2 Types of Distributed Generation [1]-[5]

DG can be classified into two major groups, inverter based DG and rotating machine DG. Usually inverters are used in DG systems after the generation process, as the generated voltage may be in DC form or AC but it is required to be changed to the nominal voltage and frequency so it has to be converted first to DC then back to AC with the nominal parameters through the rectifier.

2.2.1 Photo voltaic

PV system is an environment friendly system as it has no emissions what so ever. PV systems utilise the sun as its fuel to generate DC voltage with a range of few megawatts then transferred to AC with the aid of inverters. A PV system consists of cells placed in an array that is either fixed or moving through motors to keep tracking the sun for maximising the power generated. PV systems occupy large spaces to be able to generate sufficient power and this is one of its disadvantages besides the high initial cost.

2.2.2 Wind Turbines

Wind turbines utilise the wind as its input to be converted to useful electricity as the output of the system. It acts as a turbine with the wind as its prime mover to rotate the turbine that is connected to the shaft of a generator. The generator gives an AC output voltage that is dependent on the wind speed. As wind speed is variable so the voltage generated has to be transferred to DC and back again to AC with the aid of inverters. The range of power generated by wind turbines could be a few mega watts for each turbine.

2.2.3 Fuel Cells

Operation of fuel cells is similar to that of a battery but it is continuously charged with hydrogen which can be extracted from any hydro-carbon source, this is the charge of the fuel cell along with air (oxygen). The fuel cell utilises the reaction of hydrogen and oxygen with the aid of an ion-conducting electrolyte to produce an induced DC voltage which is proportional to the number of fuel cells. The generated DC voltage is converted to AC using an inverter. A fuel cell also produces heat and water along with electricity but it has a high running cost which is its major disadvantage. The major advantage of a fuel cell is that there are no moving parts which increases the reliability of this technology and no noise is generated; besides no fuel is consumed except for electricity generation.

2.2.4 Micro-Turbines

The technology of micro-turbines is based on very high speed rotating turbines along with a generator to produce a high frequency output voltage. Micro-turbines are usually operated by natural gas. The main advantage of micro-turbines is the clean operation with low emissions produced, but on the other hand its disadvantage is the high level of noise produced and the low efficiency.

The output voltage from micro-turbines cannot be utilised or connected to the utility, it has to be transferred to the nominal voltage with the nominal frequency, thus it has to be first converted to DC and then converted back again to AC with the nominal voltage and frequency by the aid of inverters. Micro-turbines can operate in both stand alone and parallel modes, but in the case of parallel operation with the utility grid they have to be designed to supply a fixed power output. Many benefits can be obtained from operating micro-turbines in the stand-alone mode such as the use of micro-turbines to regulate both the voltage and frequency besides the supply of active power.

2.2.5 Rotating Machines

Rotating machine types are the DGs that include induction or synchronous machines such as induction and synchronous generators. Synchronous types operate with fuel as its input to generate electricity, and can be of different ratings starting from kW range up to few MW ratings. Rotating machines are mainly used as standalone systems or as backup generation systems.

2.3 Impact of Distributed Generation on Power System Grids

Penetration of DG in Distribution networks has an impact on various fields. These impacts could be positive or negative and are considered as the benefits and drawbacks of the distributed generation. This part is addressing the impacts of DG on different aspects of the network.

2.3.1 Impact of DG on Voltage Regulation

The main regulating method used in radial distribution systems is by the aid of load tap changing transformers at substations [6], additional line regulators on distribution feeders and switched capacitors on feeders. Through the performance of the mentioned devices voltages are usually maintained within the required ranges. The criteria of voltage regulation is based on radial power flow from the substation down to all loads, DG penetration changes the radial characteristics and the system loses its radiality and power flows in different directions and a new power flow scheme is introduced.

Losing radiality of the system impacts the effectiveness of standard voltage regulation technique. An expressive example of the impact of DG on voltage regulation, if a DG is located just downstream of a voltage regulator or LTC (Load Tap Changer) transformer that is using a set line drop compensation as shown in Fig. 2.1, regulation controls will not properly measure the feeder demand [6].

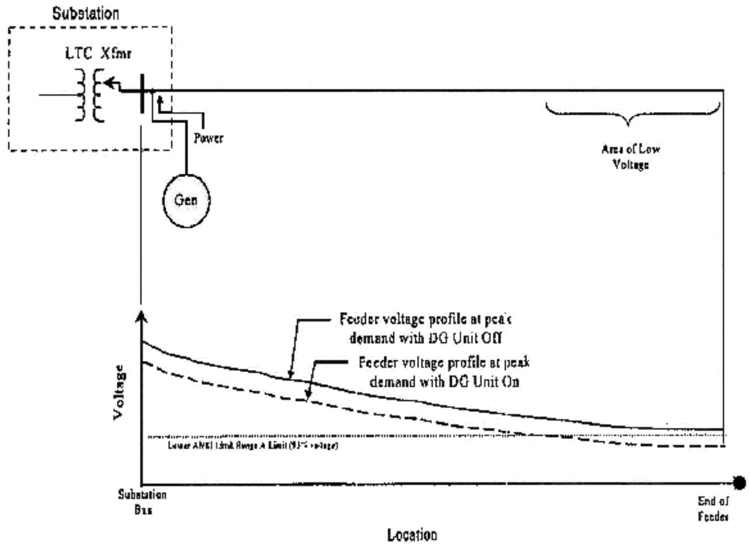

Fig. 2.1: Illustrating the DG unit interference with voltage regulation in a distribution feeder. Line drop compensation must be employed at the LTC control to result in the indicated voltage profiles. [6]

Fig. 2.1 shows the voltage profiles under these conditions with and without the presence of DG. It is clear that with distributed generation the voltage becomes lower on the feeder. The reason why the voltage is reduced in this case is because the DG causes a reduction in the observed load from the line drop compensator control side, and this will cause confusion to the regulator in setting a voltage less than the voltage which is required to maintain certain levels at the end of the feeder. This phenomenon has an opposite effect to voltage support. This is one of the benefits of DG. There are two possible solutions to the previously mentioned problem; the first solution is to move the DG unit to the upstream side of the regulator, while the second solution is adding regulator controls to compensate for the DG output. These are the solutions to this problem, but there arises other issues that are not focused on in this thesis.

One of the major effects of DG is that it may result in an increase in the voltage received at other load points connected to it. An example to this situation is, consider a small rated DG system used for residential purposes sharing a common distribution transformer with several loads, this may cause a rise in the voltage on the secondary which is sufficient to cause an increase in the voltage at the loads connected to the same distribution transformer. This case will probably occur if the distribution transformer serving these loads is placed at a point on the distribution feeder where the primary voltage is near or above the ANSI upper limit, this limit is 5% more than the nominal base voltage. In the normal condition which is without the presence of DG, there is a voltage drop across the distribution transformer and secondary conductors which results in a decrease in the voltage received at the load terminals at which this voltage is less than the primary voltage of the transformer. The presence of the DG will cause a reverse power to oppose this normal voltage drop and may cause a considerable increase in the voltage resulting in a rise of the voltage in a way that it may actually be higher at the loads terminals than that on the primary side of the distribution transformer. It can exceed the ANSI upper limit [6].

The previous examples showed how both high and low terminal voltages can occur as a result of the incompatibility of DG with the radial power flow based voltage regulation approach used on most utility systems, consequently the DG impact on voltage levels for any potential application must be assessed to ensure that all loads will not be affected or impacted by the presence of the DG. It is recognised that the power injected to the system by the DG may result in an acceptable within limits voltage at the DG side but on the other hand it might result in a voltage that will be out of limits moving towards the downstream of the DG.

2.3.2 Impact of DG on Losses

One of the major impacts of Distributed generation is on the losses in a feeder. Locating the DG units is an important criterion that has to be considered to be able to reach a better performance of the system with reduced losses, and this is used to reach an optimal performance of the network. According to [6], Locating DG units to minimise losses is similar to locating capacitor banks to reduce losses; the major difference between both cases is that DG may contribute to both active and reactive power flow (P and Q) of the system while capacitor banks will only contribute to the reactive power flow (Q) of the system. Most generators in the system will operate at a power factor range between 0.85 lagging and unity, but the presence of inverters is able to provide a contribution to reactive power compensation (leading current).

The optimum location for placing the DG can be obtained with the aid of load flow analysis software that is able to investigate the location of DG to reduce the losses in the system. Considering feeders with high losses, adding a number of small capacity DGs with a total output of 10–20% of the feeder demand will show a significant positive effect on losses and it will be reduced which is a great benefit to the system, but when deciding optimum DG location this is a theoretical decision as most of the DGs are owned by individuals, and the electric authorities or utilities do not have any influence on the locations at which the DG is required to be embedded [6]. If the analysis shows that larger DG units are required other factors have to be considered in the study, such as feeder capacity due to the thermal capacity of overhead lines and underground cables because these elements of the network may not withstand the injected currents from the DG and will result in a poor or weak distribution system with a lot of weak points and the possibility of consequent undesirable consequences might take place [6].

2.3.3 Impact of DG on Harmonics

DG can be a source of harmonics to the network; harmonics produced can be either from the generation unit itself (generator) or from the power electronics equipment such as inverters used to transfer the generated form of electricity (DC) to AC to be injected to the network. The old inverter technologies that were based on SCR produced high levels of harmonics, while the new inverter technology is based on IGBT's (Insulated Gate Bipolar Transistor) operating with the pulse width modulation technique in producing the generated "sine" wave [6]. This new technology produces a cleaner output with less harmonics produced that should satisfy the IEEE 1547-2003 standards [7] as expressed in Table 2.1 below. Rotating machines such as synchronous generators are another source of harmonics; this depends on the design of the windings of the generator (pitch of the coils), non-linearity of the coil, grounding and other factors that may result in significant harmonics propagation [6]. The best or the most specified synchronous generators are that with a winding pitch of 2/3 as they are the least third harmonic producers when compared with other generators with different pitches, but on the other hand the 2/3 winding pitch generators may cause more harmonic currents to flow through it from other parallel connected sources due to its low impedance[6].

Table 2.1: Maximum Harmonics Voltage Distortion for Distributed Generators as per IEEE 1547-2003. [7]

Harmonic Order	Allowed Level Relative to Fundamental (Odd harmonics)*
$h < 17$	4%
$11 \leq h \leq 17$	2%
$17 \leq h \leq 23$	1.5%
$23 \leq h \leq 35$	0.6%
$h \geq 35$	0.3%
Total Harmonic Distortion	5%

* Even harmonics are limited to 25% of odd values.

2.3.4 Impact of DG on Short Circuit Levels of the Network

Penetration of DG in a network has a direct impact on the short circuit levels of the network; it causes an increase in the fault currents when compared to the normal network conditions at which the substation is the only generating unit.

This increase will be obtained even if the DG is of a small generating capacity. The contribution of DG to faults depends on some factors such as the generating capacity of the DG (size of the DG), the distance of the DG from the fault location and the type of DG.

Consider a case at which one small DG is embedded in the system, the fault current will be increased at different fault locations and it can be generalised at any fault location in the entire network but the percentage increase in the fault current caused by the presence of one small DG might not be severe to the extent that causes an effect on the fuse-breaker protection scheme and it might not cause mis-coordination of the protection scheme and the fuse saving technique might still be maintained under this condition this will be discussed later in this chapter. If more than one small DG is embedded in the system, the sum of the current contribution of these DGs to fault could have a significant effect on the protection devices and may cause mis-coordination in protection scheme and the there will be no co-ordination between protective devices resulting in a failure of the protection scheme. Thus the fuse saving technique of laterals will be no more effective, consequently reliability and safety of the distribution network is affected in a negative behavior which is not acceptable.

Embedding one centralised DG in the system will have a quite significant effect on the increase of the level of short circuit currents in the system. The presence of DG on the system decreases the utility contribution to faults but on the other hand, the value of the fault current increases, this increase is due to the contribution of the DG to the fault. The percentage contribution of the DG to fault is varied according to the distance of the DG from the fault but in all conditions the fault current is increased. When placing a group of decentralised DGs distributed in different locations of the network with a total equal to that of the centralised DG mentioned previously, the fault current is still increased more than the normal condition but it is less than the centralised DG case. A detailed discussion about centralised and decentralised DG is at chapter 3 of this thesis. The highest contributing DG to faults is the separately excited synchronous generator but during the first few cycles it is equated with the induction generator and self excited synchronous generator, while after the first few cycles the separately excited synchronous generator is the most severe case. The least severe DG type is the inverter type, in some inverter types the fault contribution lasts for less than one cycle [8]-[12]. This shows that the type of DG and inverter used has a great effect on the severity of contribution to faults.

2.4 Interconnection Protection

For a DG to be embedded in the system it has to be connected to the network through an interconnection point called the point of common coupling (PCC) that usually faces a lot of problems, thus it has to be properly protected to avoid any damage to both parties during fault conditions; the first is the DG equipment and second is the utility equipment, This allows the DG to operate in parallel with the utility grid. For interconnecting the DG to the distribution utility grid, there are some protection requirements that are established by the utility. Proper interconnection protection should consider both parties ensuring the fulfilment of the utility requirements. Interconnection protection is usually dependent on some factors such as size, type of generator, interconnection point and interconnecting transformer connection. Transformers used to interconnect the DG to the utility network are classified into two main categories which is either grounded primary transformer or ungrounded primary transformer. Protection is performed at the point of common coupling (PCC) between the utility and the DG; it can be either at the primary or at the secondary of the transformer according to both the utility and the DG requirements [12]. To fulfill the desired scenario the protection is based on the following factors [12]-[16]:

(1) Protection should respond to the failure of parallel operation of the DG and the utility.

(2) Protecting the system from fault currents and transient over voltages generated by the DG during fault conditions in the system.

(3) Protecting the DG from hazards facing it during any disturbance occurring in the system such as automatic reclosing of automatic reclosers as this can cause severe troubles depending on the type of the generator used by the DG.

(4) Network characteristics at the point of DG interconnection

(5) Considering the capability of power transfer at the interconnection point

(6) Interconnection type

One of the most important protection devices used is the generator protection, and is typically located at the terminals of the generator. It is responsible of detecting internal short circuits and abnormal operating conditions of the generator itself such as: loss of field, reverse power flow, over excitation of the generator and unbalanced currents. Utilities are concerned with certain aspects that are specified such as [13], [16]:

(1) Configuration of the interconnecting transformer winding

(2) Current and voltage transformer requirements

(3) Interconnection relays class.

(4) Speed of DG isolation to be higher than that of the utility system automatic reclosing during fault conditions to avoid islanding cases.

2.5 Islanding of a Power Network

Islanding has two forms, either intentional islanding that is performed on purpose by the utility to increase the reliability of the network; the other form of islanding is unintentional islanding, it can be expressed in other words as “the loss of mains” and this occurs when the distributed generator is no more operating in parallel with the utility. Thus, it is not connected to the utility due to a protective disconnection operation taking place by one of the protection devices in the network which could be breaker, fuse or automatic recloser. The DG now is left to energise a certain part of the network that is separated from the utility network forming an isolated power island with the DG as the only power source. The difficulties in islanding cases are due to the ability of the DG to generate power while disconnected from the utility, thus the DG is no more controlled by the utility protection devices and continues feeding its own power island. Islanding can occur only if a generator or a group of generators located in the isolated part are capable of sustaining all the loads in that portion of the network. Forming an isolated power island imposes a difficulty in the reconnection of the isolated power island back to the utility network.

Islanding has an impact on the safety of both the utility and the connected loads, all customer loads connected to this power island will face fluctuations in both voltage and frequency, and those fluctuations might cause severe damages as the voltage and frequency at their terminals are deviated than the standard required levels [17]. It is not desirable for a DG to island with any part of the utility system because if a feeder faces an island reclosing operations, the islanded DG will rapidly drift out of phase with the utility system [6]. After another reclose, the utility will be connected out of phase with the isolated power island, in the case of the absence of blocking the reclose or connection to an energised circuit in the control of the breaker control. Allowing the connection might cause a severe damage to the utility equipment.

2.5.1 Islanding Detection

Nowadays the techniques used in detecting islanding situations is by measuring the output parameters of the DG and a decision is taken to decide whether these parameters express an islanding situation or not. Islanding detections methods could be classified in two main groups which are basically active methods and passive methods. The major difference between active and passive methods is that active methods is directly interacting with the power system operation while passive methods are based on identifying the problem based on measured system parameters.

Active detection methods realise the islanding situation by measuring the changes in the output power and the system frequency through a designed control circuit providing the necessary variations. During the connection of the DG to the utility, there will be a negligible change occurring in the frequency or power flow that will not be sufficient for the initiation of the protective relay that is responsible for the DG isolation. On the other hand, if the DG is not connected to the utility network, the changes in the frequency and output power will be sufficient enough to energise the relay resulting in the disconnection of the DG preventing the occurrence of an islanding situation. The previously mentioned method will not be efficient in the case of a balance between the loads connected and generation in an islanded part of the network as there will be a non detective zone (NDZ), which is defined as “the island load values for which the detection method fails to detect islanding” from,[18]-[20].

Passive detection methods monitor the variations occurring in the power system parameters such as the short circuit levels, phase displacement and the rate of output power as in most cases of utility disconnection the nominal network voltage, current and frequency are affected. A passive method utilises these changes to decide and react to an islanding situation. Passive methods have the same weakness as the active methods against the insignificant mismatch between the generation and load in islanded part [21] but on the other hand passive methods are less expensive than active methods.

During the past few decades, several islanding detection methods were introduced to protect the distribution systems with DG from the case of unintentional islanding. One of the direct and efficient methods is by monitoring the trip status of the main utility circuit breaker and as soon as the main circuit breaker trips, an immediate signal is sent to the circuit breaker at the interconnection between the DG and the utility system to trip the interconnection circuit breaker preventing the occurrence of islanding. Although this method seems to be easy and straight forward, its implementation is so difficult due the distribution of DGs in a large geographic range that will require special comprehensive monitoring techniques with dedicated systems.

2.6 Impact of DG on Distribution Feeder Protection

One of the main symptoms of distribution systems is the radiaility of power flow. Power is flowing in the network from the main generating station down to various parts of the system to supply all loads. To maintain continuous supply to all loads and preventing all appliances and different components of the system from power outages, protection devices are placed on feeders and laterals of the distribution network, these protection devices are basically overcurrent protection devices.

During the design process of these protection devices, some characteristics have to be taken into consideration and bearing in mind that it is impossible to protect the entire network directly from the substation, it is essential in large networks to provide it with several protective devices due to the fact that any protective device has a reach or maximum distance to cover. When designing the protection scheme of a network coordination between different types of protection devices has to be considered to be able to reach a highly reliable network that will be able to isolate only the faulted parts of the network and keeping the healthy parts energised which increases the reliability of the network. The presence of DG in a network will have a great impact on the coordination of the protective device, thus it affects the distribution feeder protection. It also has a great impact on the utility protection devices. Impacts of DG on protection devices are [6], [22], [23]:

- The contribution of DG to fault currents may cause the fault level to be higher than the capacity of switching devices of the existing network, one of the factors affecting the fault current contribution is the type of DG used.
- Unintentional Islanding cases.
- There might be a resonance case that will cause over voltages
- Sympathetic tripping of protective devices
- Failure of fuse protection technique
- Mis-protection as a result of the network's reconfiguration
- Reduced reach of protective device
- Loss of coordination between protective devices.
- Loosing sensitivity to faults and not tripping in fault conditions due to inability to detect faults currents.

2.6.1 Sympathetic Tripping

The penetration of a DG in an existing distribution network results in a considerable increase in the fault short circuit currents in some parts of the network, but it causes an increase in the fault levels for any fault location in the entire network. This increase causes a lot of problems to the existing protection devices in the network, the type of protection defect depends on the situation of the DG and where it is placed in the network as the penetration of DG changes the configuration of the network parameters.

"Sympathetic tripping" is an expression given to the case at which one of the protection devices trips instead of the other. This tripping occurs due to one device detecting the fault while it is out of its local protection area and tripping before the required tripping device [22], [23]. This type of tripping causes the isolation of a healthy part of the network while it is not required to be isolated, and this reduces the reliability of the distribution network. Fig. 2.2 below presents a typical sympathetic tripping situation.

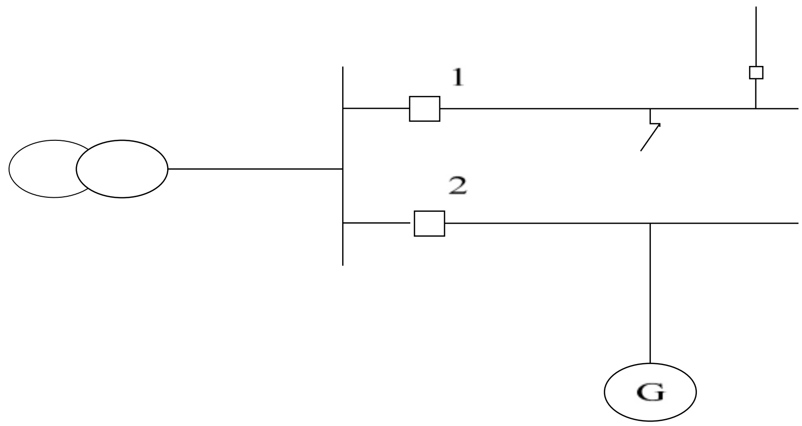

Fig. 2.2: A typical sympathetic tripping situation

In the configuration shown in the above figure, when the fault occurs, relay and breaker 1 are the prime devices that should trip to isolate the faulted branch leaving all the healthy parts operating normally. In this situation relay and breaker 2 which should be the backup of relay and breaker 1, but they will trip first. This tripping is a result of the additional current injection of the DG to the fault which was not taken into consideration during the original feeder protection design, so relay 2 will sense the rise in current flowing through it and interpret it to a fault condition and consequently a trip takes place.

2.6.2 Reduction of Reach of Protective Devices

The presence of a DG in the distribution network may cause a protection deficiency called “reduction of reach”. This is the failure of the protection devices to cover its designed protective distance, as the DG causes a decrease in the sensitivity of these protection devices [23], thus decreasing the distance protected. Fig. 2.4 below illustrates an example at which reduction of reach of protective devices is introduced.

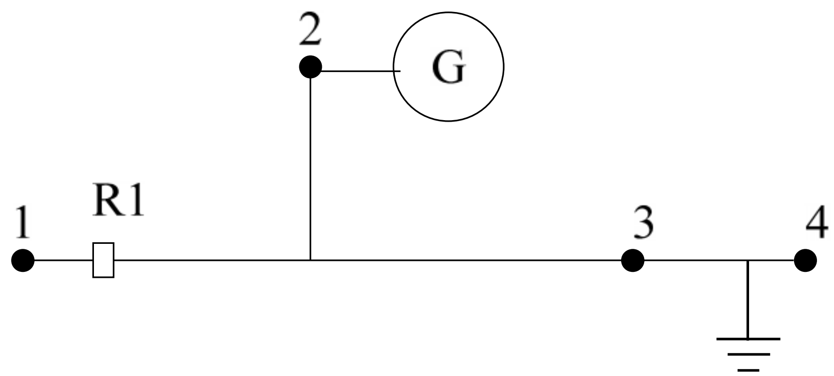

Fig. 2.3: Reduction of reach of R1

R1 is designed to cover the whole line from node 1 to node 4, the presence of the DG will cause a change in the apparent impedance of the line which causes a mis-estimation of R1 [17]. When the fault is at the end of the line as shown in the above figure R1 will not be able to sense the fault due to the flow of fault current from the DG.

2.6.3 Failure of Fuse Saving Technique Due to Loss of Recloser-Fuse Coordination

Electricity is usually supplied to loads in distribution systems through radial distribution feeders then through laterals and transformers to the loads. To be able to protect the system components and loads besides providing the desired safety, protection equipment must be placed along the network at various places according to the function of each piece of equipment. The most common protection technique for protecting laterals in distribution networks is by using a fuse. The fuse is coordinated with other protection equipment of the network such as recloser and breaker, to be able to save the fuse from blowing out in case of temporary faults [23], this is to reduce the power outages as it is not required to interrupt the system during temporary faults due to the fact that these faults are considered to be around 70 to 80 percent of the occurring faults, an example of these faults is lightning which is instantaneous then it disappears. The main concern is the permanent fault, at which the automatic recloser cannot clear. Figure 2.4 below shows part of a distribution network involving recloser, fuse and breaker without the presence of a DG.

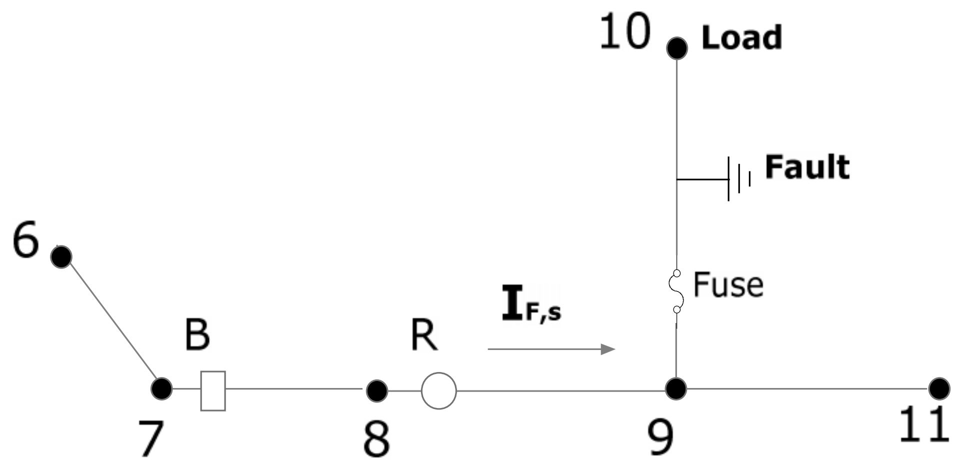

Fig. 2.4: Part of a distribution network including recloser, fuse and breaker.

The current flowing through the recloser is the same as the current flowing through the fuse during the fault condition illustrated in the above figure. The recloser has an inverse time over current characteristic.

Penetration of a DG in the network will result in the radial characteristics of the power flow in the network; it becomes a mesh power flow. DG contributes to fault currents which increase the fault current values; this increase might cause the failure of fuse saving technique. Fig. 2.5 below shows the same network as Fig. 2.4 but with the presence of a DG at node 11.

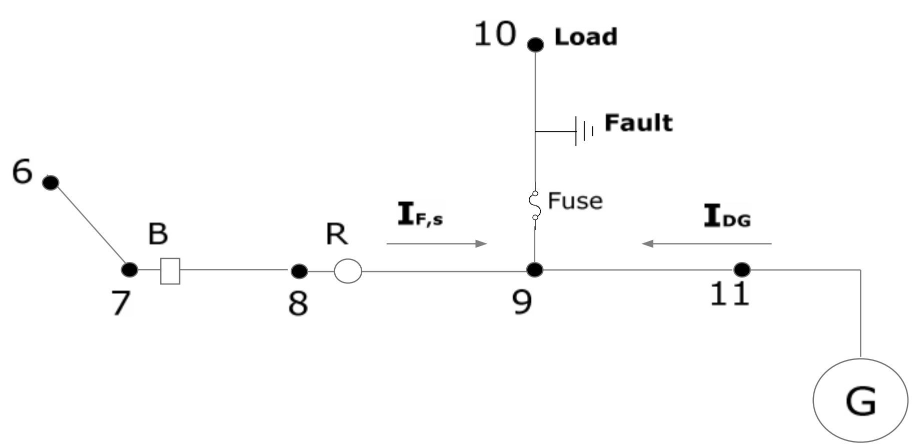

Fig. 2.5: Network after adding DG.

The fault current flowing through the recloser in this case is the fault current contributed by the substation (utility) only, while the fault current flowing through the fuse is a sum of both the current contributed from the DG to the fault and the fault current contributed from the substation or the utility. The increase in the fault current flowing through the fuse could be sufficient to initiate the blowing of the fuse before the recloser operation. To overcome the problem of the fuse operating before the recloser, coordination has to be made between the fuse and the recloser. Fig. 2.6 below illustrates the coordination between the recloser and the fuse [24].

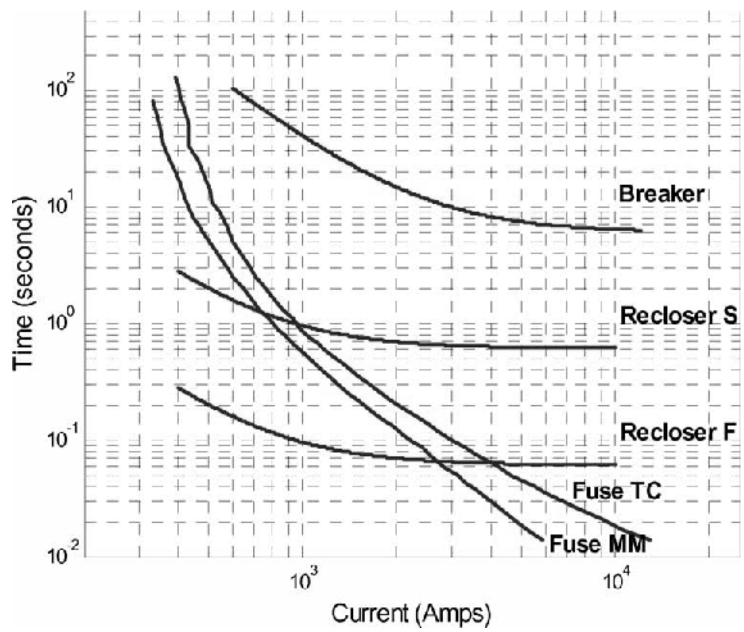

Fig. 2.6: Coordination between Recloser, Fuse and Circuit Breaker [25].

In Fig. 2.6, "**RECLOSER A**" represents the fast mode operation curve of the recloser; "**RECLOSER B**" represents the slow mode operation curve of the recloser. "**FUSE MM**" represents the fuse minimum melt characteristics of the fuse and "**FUSE TC**" represents the fuse total clear characteristics of the fuse. "$\mathbf{If_{min}}$" and "$\mathbf{If_{max}}$" are the minimum and maximum permissible fault current interval at which the fault current has to fall in between for the coordination to be applicable.

A recloser has two operating modes to either clear a temporary fault or locking open for permanent fault if the fuse does not blow for permanent faults. The operating mode of a recloser is "**F-F-S-S**" [27], where "**F**" is the fast operating mode and "**S**" is the slow operating mode. The recloser attempts two consecutive trials with a difference time interval of 1 second, if the fault is a temporary fault it is expected to be cleared after the first strike of the recloser, if it strikes again the total time is now 2 seconds and the fault still exists then the fault is discriminated to be a permanent fault and the fuse has to operate to cause a permanent power outage to clear the fault. The fuse has a back up which is the recloser slow operation, if the fuse fails to clear the fault, the recloser attempts two trials before it is locked out [27]. The main purpose of coordination between fuse and recloser is to result in the least isolated area during faults by the isolation of only the faulted part of the network leaving the healthy parts energised. By achieving the required coordination of protection devices the reliability of the network is increased.

Chapter 3: Simulation of IEEE 13 Bus with Different DG Configurations

3.1 Introduction

DG is one of the most concerns nowadays, as it has a great role in fulfilling the end-user increasing requirements in a manner that increases the reliability of their power supply. Penetration of DG systems to existing distribution networks has a great impact on the short circuit levels of the system and on protective devices, there are some factors affecting this impact such as the size of the DG penetrating the system, the location at which the DG is placed and the type of DG used.

The main concern of this chapter is to investigate the effects of adding a DG to the existing network as well as the effect of a single centralised DG compared to several small distributed DGs. The system (model) studied in this chapter is the IEEE 13 bus system, and it is simulated using software named ETAP.

3.2 IEEE 13 Bus Test Feeder

The IEEE 13 bus is a small feeder, but it displays many features and is considered as a model that can be used to investigate the behaviour of a power system for the desired simulation. The features of the IEEE 13 node test feeder is basically the presence of over head and underground lines, distributed and spot loads, capacitor banks and a 500 kVA inline transformer. Fig. 3.1 shows the schematic layout of the IEEE test feeder used as the model to be simulated [26], without showing the different connected loads or the nature and configuration of the transmission components of the network. There are some assumptions taken into consideration while performing the simulation, these assumptions are listed below.

1) The effect of voltage regulator at bus 650 is not taken into consideration in the calculations
2) Distributed loads between buses 671 and 632 are not taken into consideration in the calculation.
3) The type of DG used is wind turbine.
4) The type of wind turbine is a doubly fed induction generator.

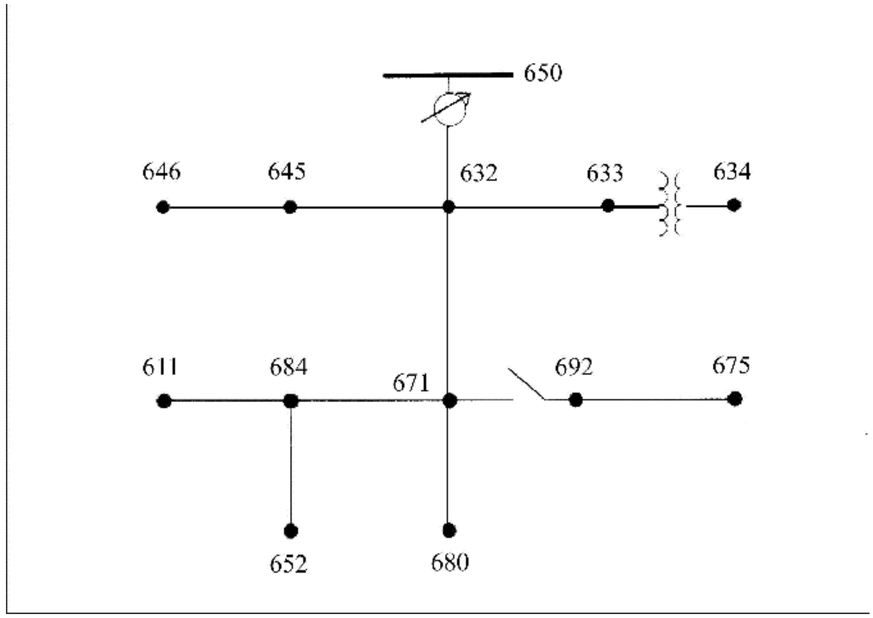

Fig.3.1: Illustrating the IEEE 13 test feeder [26]

3.2.1 Load Models

There are different load models used in this test feeder. The loads are classified into either spot or distributed; all loads are either three phase or single phase. Each and every load model is given a separate code that will be shown in Table 3.1 [27].

Table 3. 1: Listing the load models [27]

Code	Connection	Model
Y-PQ	Wye	Constant KW, constant kVAR
Y-l	Wye	Constant Current
Y-Z	Wye	Constant Impedance
D-PQ	Delta	Constant KW, constant kVAR
D-l	Delta	Constant Current
D-Z	Delta	Constant Impedance

Spot load configuration in the network is presented in Table 3.2. All load values are in either kW or kVAr according to the load nature.

Table 3.2: Expressing spot load configuration in IEEE test feeder [26]

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-3 kVAr
634	Y-PQ	160	110	120	90	120	90
645	Y-PQ	0	0	170	125	0	0
646	D-Z	0	0	230	132	0	0
652	Y-Z	128	86	0	0	0	0
671	D-PQ	385	220	385	220	385	220
675	Y-PQ	485	190	68	60	290	212
692	D-I	0	0	0	0	170	151
611	Y-I	0	0	0	0	170	80
	TOTAL	1158	606	973	627	1135	753

3.2.2 Over Head Lines

Over head lines have different configurations based on the number of phases and accordingly the spacing ID. Table 3.3 will show the over head lines configuration data [26].

Table 3.3: Listing the overhead line configuration data. [26]

Config.	Phasing	Phase ACSR	Neutral ACSR	Spacing ID
601	BACN	556, 500 26/7	4/0 6/1	500
602	CABN	4/0 6/1	4/0 6/1	500
603	CBN	1/0	1/0	505
604	ACN	1/0	1/0	505
605	CN	1/0	1/0	510

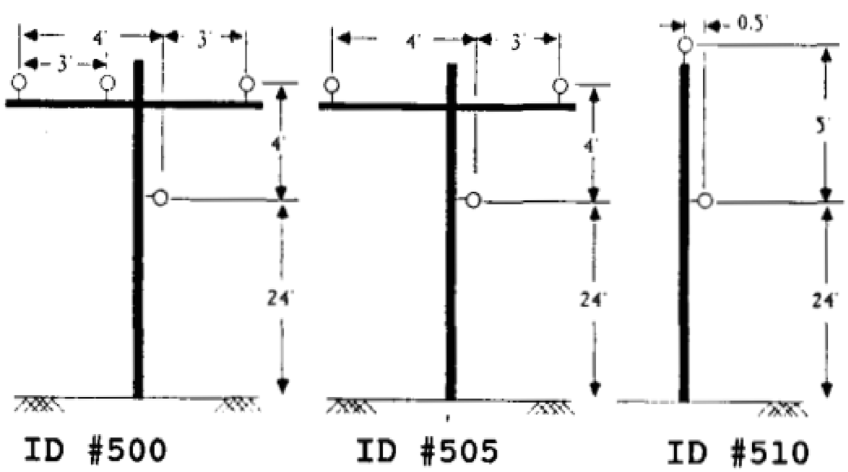

Fig.3.2: Overhead line spacing. [27]

Table 3.4 Shows the spacing ID coding [26]

Spacing ID	Type
500	Three phase, 4 wires
505	Two phase, 3 wires
510	One phase, 2 wires

Table 3.5: Listing the line segment data. [26]

Node A	Node B	Length(ft.)	Config.
632	645	500	603
632	633	500	602
633	634	0	XFM-1
645	646	300	603
650	632	2000	601
684	652	800	607
632	671	2000	601
671	684	300	604
671	680	1000	601
671	692	0	Switch
684	611	300	605
692	675	500	606

Table 3.6: Underground cable configuration [26]

Config.	Phasing	Cable	Neutral	Space ID
606	A B C N	250,000 AA, CN	None	515
607	A N	1/0 AA, TS	1/0 Cu	520

3.2.3 Transformers

Below is a table listing the specifications of both the utility and the inline transformers

Table 3.7: Transformer data [26]

	kVA	kV-high	kV-low	R - %	X - %
Substation:	5,000	115 - D	4.16 Gr. Y	1	8
XFM -1	500	4.16 – Gr.W	0.48 – Gr.W	1.1	2

3.2.4 Shunt Capacitor Banks

The details of capacitor banks used in the IEEE test feeder are listed in table 3.8 below.

Table 3.8: Capacitor data. [26]

Node	Ph-A	Ph-B	Ph-c
	kVAr	kVAr	kVAr
675	200	200	200
611			100
Total	200	200	300

3.3 Cases Studied and Simulation Results

In this section simulation was made on the IEEE 13 bus using ETAP with nine different DG configurations to study the impacts of DG penetration into power networks, the contribution of DGs to fault currents and its effect on short circuit levels at all buses and branches in various cases. First part of this section will introduce the system under study followed by the simulation results and the last part is a discussion on the simulation results.

3.3.1 System Under Study

The system under study is the IEEE 13 bus, it is used with different configurations of DG with and without DG to calculate the base or set values to compare all configuration results with. Fig. 3.3 is showing the basic IEEE 13 bus without the presence of any DG.

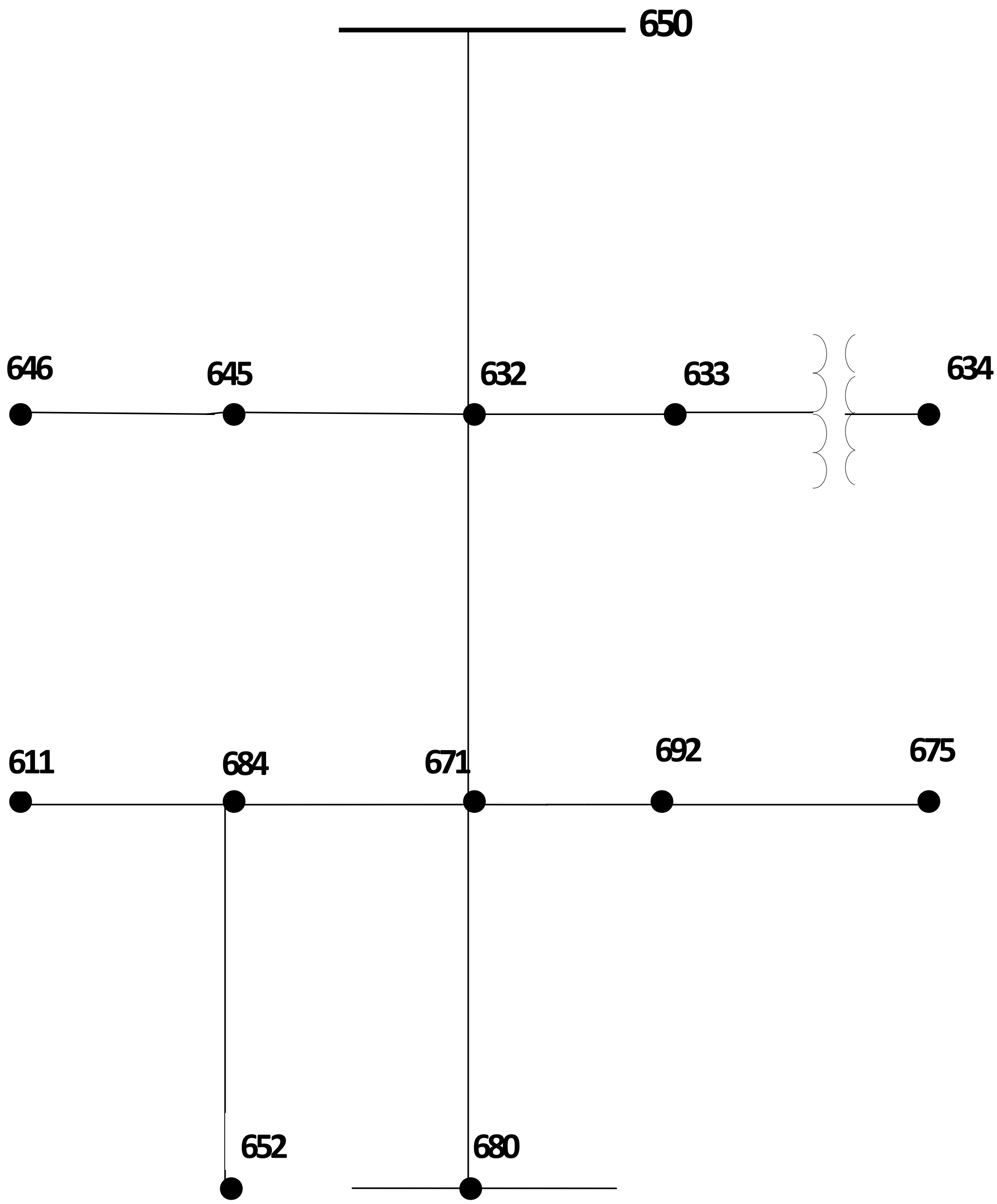

Fig.3.3: IEEE 13 bus system under study

3.3.2 Case 1: IEEE 13 Bus without DG

The system was simulated without any DG penetration and tables of results for this case are listed below.

Note: Simulation is made with a pre voltage= 4.16 kV & 100% of normal voltage is 4.6 kV and 100% of base kV= 4.16 kV

Table 3.9: lists the positive, negative & zero sequence impedances seem from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.06928	0.20236	0.21389	0.06928	0.20236	0.21389	0.18462	0.38503	0.42700
Bus633	4.160	0.12353	0.27194	0.29869	0.12353	0.27194	0.29869	0.27073	0.55637	0.61874
Bus634	0.480	0.00631	0.01221	0.01375	0.00631	0.01221	0.01375	0.00734	0.01453	0.01628
Bus671	4.160	0.10712	0.36026	0.37585	0.10712	0.36026	0.37585	0.26789	0.80107	0.84468
Bus675	4.160	0.14403	0.39424	0.41973	0.14403	0.39424	0.41973	0.31698	0.83323	0.89148
Bus680	4.160	0.14246	0.47364	0.49460	0.14246	0.47364	0.49460	0.39160	1.16385	1.22796
Bus692	4.160	0.10712	0.36026	0.37585	0.10712	0.36026	0.37585	0.26789	0.80107	0.84468

Table 3.10: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	11.229	0.00	111.23	117.88	8.444	8.444
Bus671	Bus632	11.83	1.199	17.39	107.09	111 .40	0.961	1.081
Bus633	Bus632	0.46	0.121	1.50	110.55	117.05	0.200	0.419
U2	Bus632	100.00	9.864	100.00	100.00	100.00	7.225	6.841
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.079	0.143
Bus680	Bus671	11.83	0.000	17.39	107.09	111.40	0.000	0.000
Lump3	Bus671	100.00	0.644	100.00	100.00	100.00	0.323	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.065	0.110
Bus675	Bus692	12.93	0.499	19.16	107.89	109.80	0.574	0.971
Bus634	Bus633	4.42	0.121	8.07	108.72	114.34	0.200	0.419
Lump4	Bus675	100.00	0.499	100.00	100.00	100.00	0.574	0.971
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.733	3.632
Bus692	Bus671	11.83	0.499	17.39	107.09	111.40	0.574	0.971

Table 3.11: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	8.041	0.00	114.69	116.18	5.925	5.925
Bus632	Bus633	29.87	7.920	31.19	107.70	111.08	5.720	5.489
Bus634	Bus633	3.99	0.121	6.75	112.53	113.40	0.205	0.437
Bus671	Bus632	38.17	0.855	43.16	104.93	107.04	0.666	0.740
U2	Bus632	100.00	7.032	100.00	100.00	100.00	5.014	4.679
Lump9	Bus632	100.00	0.045	100.00	100.00	100.00	0.055	0.098
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.780	3.789
Bus680	Bus67l	38.17	0.000	43.16	104.93	107.04	0.000	0.000
Lump3	Bus671	100.00	0.459	100.00	100.00	100.00	0.226	0.000
Lump?	Bus671	100.00	0.040	100.00	100.00	100.00	0.045	0.076
Bus675	Bus692	39.01	0.356	44.37	105.47	105.93	0.396	0.664
Lump4	Bus675	100.00	0.356	100.00	100.00	100.00	0.396	0.664
Bus692	Bus671	38.17	0.356	43.16	104.93	107.04	0.396	0.664

Table 3.12: 3-phase & single line to ground fault currents when fault is At bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	20.157	0.00	103.28	102.75	18.991	18.991
Bus633	Bus634	72.28	19.066	65.55	104.48	104.36	17.289	15.944
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.706	3.056
Bus632	Bus633	80.48	2.200	76.27	102.35	103.17	1.995	1.840
Bus671	Bus632	82.82	0.238	80.37	101.51	102.00	0.232	0.248
U2	Bus632	100.00	1.953	100.00	100.00	100.00	1.749	1.568
Lump9	Bus632	100.00	0.013	100.00	100.00	100.00	0.019	0.033
Bns680	Bus671	82.82	0.000	80.37	101.51	102.00	0.000	0.000
Lump3	Bus671	100.00	0.128	100.00	100.00	100.00	0.080	0.000
Lump7	Bus671	100.00	0.011	100.00	100.00	100.00	0.015	0.025
Bus675	Bus692	83.04	0.099	80.76	101.69	101.63	0.136	0.223
Lump4	Bus675	100.00	0.099	100.00	100.00	100.00	0.136	0.223
Bus692	Bus671	82.82	0.099	80.37	101.51	102.00	0.136	0.223

Table 3.13: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus67l	Total	0.00	6.390	0.00	116.55	118.40	4.514	4.514
Bus632	Bus671	49.79	5.048	55.85	102.84	106.43	3.395	3.053
Bus680	Bus671	0.00	0.000	0.00	116.55	118.40	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.344	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.080	0.151
Bus675	Bus692	1.45	0.565	3.28	117.43	116.18	0.709	1.329
Bus633	Bus632	50.00	0.061	56.46	102.64	106.11	0.086	0.173
U2	Bus632	100.00	4.956	100.00	100.00	100.00	3.275	2.825
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.059
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.709	1.329
Bus634	Bus633	51.98	0.061	59.24	102.13	105.08	0.086	0.173
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.747	1.500
Bus692	Bus671	0.00	0.565	0.00	116.55	118.40	0.709	1.329

Table 3.14: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus675	Total	0.00	5.722	0.00	115.68	116.42	4.163	4.163
Bus692	Bus675	13.23	5.163	11.99	116.86	113.72	3.463	2.882
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.719	1.325
Bus632	Bus671	55.59	4.470	59.85	103.44	104.84	3.083	2.750
Bus680	Bus671	13.23	0.000	11.99	116.86	113.72	0.000	0.000
Lump3	Bus67l	100.00	0.646	100.00	100.00	100.00	0.313	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.073	0.136
Bus633	Bus632	55.79	0.054	60.42	103.23	104.58	0.078	0.156
U2	Bus632	100.00	4.389	100.00	100.00	100.00	2.975	2.544
Lump9	Bus632	100.00	0.028	100.00	100.00	100.00	0.031	0.053
Bus634	Bus633	57.56	0.054	62.98	102.66	103.75	0.078	0.156
Lump1	Bus634	100.00	0.466	100.00	100.00	100.00	0.676	1.350
Bus671	Bus692	13.23	5.163	11.99	116.86	113.72	3.463	2.882

Table 3.15: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	4.856	0.00	119.14	120.88	3.250	3.250
Bus671	Bus680	24.01	4.856	28.00	111.43	112.73	3.250	3.250
Bus632	Bus67l	61.83	3.836	68.19	101.99	104.58	2.444	2.198
Lump3	Bus67]	100.00	0.554	100.00	100.00	100.00	0.247	0.000
Lump7	Bus671	10000	0.048	100.00	100.00	100.00	0.058	0.109
Bus675	Bus692	24.87	0.430	29.37	112.15	111.11	0.511	0.957
Bus633	Bus632	62.00	0.046	68.63	101.85	104.35	0.062	0.125
U2	Bus632	100.00	3.766	100.00	100.00	100.00	2.358	2.034
Lump9	Bus632	100.00	0.024	100.00	100.00	100.00	0.025	0.042
Lump4	Bus67J	100.00	0.430	100.00	100.00	100.00	0.511	0.957
Bus634	Bus633	63.50	0.046	70.64	101.50	103.62	0.062	0.125
Lump1	Bus634	100.00	0.400	100.00	100.00	100.00	0.538	1.080
Bus692	Bus671	24.01	0.430	28.00	111.43	112.73	0.511	0.957

Table 3.16: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	6.390	0.00	116.55	118.40	4.514	4.514
Bus675	Bus692	1.45	0.565	3.28	117.43	116.18	0.709	1.329
Bus632	Bus67I	49.79	5.048	55.85	102.84	106.43	3.395	3.053
Bus680	Bus67l	0.00	0.000	0.00	116.55	118.40	0.000	0.000
Lump3	Bus67l	100.00	0.730	100.00	100.00	100.00	0.344	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.080	0.151
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.709	1.329
Bus633	Bus632	50.00	0.061	56.46	102.64	106.11	0.086	0.173
U2	Bus632	100.00	4.956	100.00	100.00	100.00	3.275	2.825
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.059
Bus634	Bus633	51.98	0.061	59.24	102.13	105.08	0.086	0.173
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.747	1.500
Bus671	Bus692	0.00	5.830	0.00	116.55	118.40	3.812	3.200

Table 3.17: Summary of fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	3.637	-10.624	11.229	3.198	-7.815	8.444	9.200	3.150	9.725	-10.589	-0.071	10.589
Bus633	4.16	3.326	-7.321	8.041	2.523	-5.361	5.925	6.340	2.880	6.964	-7.356	-0.766	7.395
Bus634	0.48	9.253	-17.909	20.157	8.661	-16.901	18.991	15.509	8.013	17.457	11.440	16.013	19.679
Bus671	4.16	1.821	-6.125	6.390	1.364	-4.303	4.514	5.305	1.577	5.534	-5.848	0.081	5.848
Bus675	4.16	1.964	-5.375	5.722	1.455	-3.900	4.163	4.655	1.700	4.956	-5.232	-0.170	5.235
Bus680	4.16	1.399	-4.650	4.856	0.992	-3.095	3.250	4.027	1.211	4.205	-4.410	-0.052	4.411
Bus692	4.16	1.821	-6.125	6.390	1.364	-4.303	4.514	5.305	1.577	5.534	-5.848	0.081	5.848

In the case of **line-to line-to-ground fault** there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer.

All the above tables in this case represent the system's base values at which all protection devices are set based on the system's response to faults without any external effects on the system. The results recorded in the above tables of this sub-section are going to be compared with all values of the following cases to observe the impact of DG when embedded in the system.

3.3.3 Case 2: IEEE 13 Bus with 1*8 MW DG Located at bus 632

In this section IEEE 13 bus is simulated with a DG penetration level of 8 mw centralised placed at bus 632 and the results of this case are tabulated below.

Table 3.18: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.03265	0.13992	0.14368	0.02524	0.12047	0.12309	0.18462	0.38503	0.42700
Bus633	4.160	0.08737	0.20997	0.22742	0.08006	0.19067	0.20680	0.27073	0.55637	0.61874
Bus634	0.480	0.00587	0.01145	0.01287	0.00579	0.01121	0.01262	0.00734	0.01453	0.01628
Bus671	4.160	0.08030	0.31062	0.32083	0.07506	0.29527	0.30466	0.26789	0.80107	0.84468
Bus675	4.160	0.11872	0.34519	0.36504	0.11388	0.33008	0.34917	0.31698	0.83323	0.89148
Bus680	4.160	0.11563	0.42400	0.43948	0.11039	0.40865	0.42329	0.39160	1.16385	1.22796
Bus692	4.160	0.08030	0.31062	0.32083	0.07509	0.29527	0.30466	0.26789	0.80107	0.84468

Table 3.19: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	16.717	0.00	119.65	130.59	10.451	10.451
Bus671	Bus632	11.83	1.199	18.71	113.05	120.74	0.907	1.338
Bus633	Bus632	0.46	0.121	1.75	118.67	129.40	0.219	0.519
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.632	8.467
WTGI	Bus632	100.00	5.658	100.00	100.00	100.00	2.693	0.000
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.083	0.177
Bus680	Bus671	11.83	0.000	18.71	113.05	120.74	0.000	0.000
Lump3	Bus67l	100.00	0.644	100,00	100.00	100.00	0.249	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.067	0.137
Bus675	Bus692	12.93	0.499	20,62	113.91	118.69	0.592	1.202
Bus634	Bus633	4.42	0.121	8.94	115.79	125.35	0.219	0.519
Lump4	Bus675	100.00	0.499	100.00	100.00	100.00	0.592	1.202
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.895	4.495
Bus692	Bus67I	11.83	0.499	18.71	113.05	120.74	0.592	1.202

Table 3.20: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	10.561	0.00	121.05	123.76	6.846	6.846
Bus632	Bus633	39.37	10.440	36.10	112.42	117.13	6.627	6.341
Bus634	Bus633	3.99	0.121	7.18	118.16	120.10	0.218	0.505
Bus671	Bus632	46.52	0.754	48.09	108.50	111.51	0.585	0.854
U2	Bus632	100.00	6.204	100.00	100.00	100.00	4.287	5.406
WTG1	Bus632	100.00	3.559	100.00	100.00	100.00	1.756	0.000
Lump9	Bus632	100.00	0.040	100.00	100.00	100.00	0.053	0.113
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.893	4.377
Bus680	Bus671	46.52	0.000	48.09	108.50	111.51	0.000	0.000
Lump3	Bus671	100.00	0.405	100.00	100.00	100.00	0.163	0.000
Lump7	Bus671	100.00	0.035	100.00	100.00	100.00	0.043	0.087
Bus675	Bus692	47.29	0.314	49.32	109.08	110.16	0.380	0.767
Lump4	Bus675	100.00	0.314	100.00	100.00	100.00	0.380	0.767
Bus692	Bus671	46.52	0.314	48.09	108.50	111.51	0.380	0.767

Table 3.21: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	21.536	0.00	104.31	103.82	19.905	19.905
Bus633	Bus634	77/1	20.444	68.90	105.65	105.60	18.174	16.712
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.736	3.203
Bus632	Bus633	86.30	2.359	80.17	103.36	104.29	2.097	1.928
Bus671	Bus632	87.96	0.170	83.87	102.37	102.88	0.183	0.260
U2	Bus632	100.00	1.402	100.00	100.00	100.00	1.349	1.644
WTGI	Bus632	100.00	0.804	100.00	100.00	100.00	0.566	0.000
Lump9	Bus632	100.00	0.009	100.00	100.00	100.00	0.017	0.034
Bus680	Bus67l	87.96	0.000	83.87	102.37	102.88	0.000	0.000
Lump3	Bus671	100.00	0.092	100.00	100.00	100.00	0.052	0.000
Lump7	Bus671	100.00	0.008	100.00	100.00	100.00	0.013	0.027
Bus675	Bus692	88.13	0.071	84.23	102.57	102.46	0.118	0.233
Lump4	Bus675	100.00	0.071	100.00	100.00	100.00	0.118	0.233
Bus692	Bus671	87.96	0.071	83.87	102.37	102.88	0.118	0.233

Table 3.22: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	7.486	0.00	119.65	123.41	4.904	4.904
Bus632	Bus671	60.52	6.136	61.77	104.20	109.83	3.799	3.317
Bus680	Bus671	0.00	0.000	0.00	119.65	123.41	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.311	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.082	0.164
Bus675	Bus692	1.45	0.565	3.44	120.53	120.97	0.722	1.444
Bus633	Bus632	60.70	0.048	62.40	103.96	109.45	0.082	0.188
U2	Bus632	100.00	3.900	100.00	100.00	100.00	2.602	3.069
WTG1	Bus632	100.00	2.237	100.00	100.00	100.00	1.116	0.000
Lump9	Bus632	100.00	0.025	100.00	100.00	100.00	0.031	0.064
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.722	1.444
Bus634	Bus633	62.26	0.048	65.04	103.32	108.14	0.082	0.188
Lump1	Bus634	100.00	0.414	100.00	100.00	100.00	0.708	1.629
Bus692	Bus671	0.00	0.565	0.00	119.65	123.41	0.722	1.444

Table 3.23: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus675	Total	0.00	6.580	0.00	118.72	120.36	4.488	4.488
Bus692	Bus675	15.42	6.018	13.04	119.86	117.55	3.776	3.107
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.730	1.428
Bus632	Bus671	66.07	5.334	65.64	104.99	107.50	3.425	2.964
Bus680	Bus671	15.42	0.000	13.04	119.86	117.55	0.000	0.000
Lump3	Bus671	100.00	0.634	100.00	100.00	100.00	0.281	0.000
Lump7	Bus671	100.00	0.055	100.00	100.00	100.00	0.073	0.147
Bus633	Bus632	66.22	0.042	66.22	104.74	107.19	0.073	0.168
U2	Bus632	100.00	3.390	100.00	100.00	100.00	2.345	2.743
WTG1	Bus632	100.00	1.945	100.00	100.00	100.00	1.010	0.000
Lump9	Bus632	100.00	0.022	100.00	100.00	100.00	0.028	0.057
Bus634	Bus633	67.58	0.042	68.62	104.05	106.15	0.073	0.168
Lump1	Bus634	100.00	0.360	100.00	100.00	100.00	0.636	1.456
Bus671	Bus692	15.42	6.018	13.04	119.86	117.55	3.776	3.107

Table 3.24: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus680	Total	0.00	5.465	0.00	121.56	124.61	3.448	3.448
Bus671	Bus680	27.02	5.465	29.70	113.11	115.62	3.448	3.448
Bus632	Bus671	71.20	4.479	73.11	102.82	106.74	2.671	2.332
Lump3	Bus671	100.00	0.533	100.00	100.00	100.00	0.218	0.000
Lump7	Bus671	100.00	0.046	100.00	100.00	100.00	0.057	0.115
Bus675	Bus692	27.87	0.413	31.10	113.84	113.87	0.508	1.015
Bus633	Bus632	71.33	0.035	73.56	102.66	106.48	0.057	0.132
U2	Bus632	100.00	2.847	100.00	100.00	100.00	1.830	2.158
WTG1	Bus632	100.00	1.633	100.00	100.00	100.00	0.784	0.000
Lump9	Bus632	100.00	0.018	100.00	100.00	100.00	0.022	0.045
Lump4	Bus675	100.00	0.413	100.00	100.00	100.00	0.508	1.015
Bus634	Bus633	72.47	0.035	75.42	102.25	105.59	0.057	0.132
Lump1	Bus634	100.00	0.302	100.00	100.00	100.00	0.498	1.145
Bus692	Bus671	27.02	0.413	29.70	113.11	115.62	0.508	1.015

Table 3.25: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus692	Total	0.00	7.486	0.00	119.65	123.41	4.904	4.904
Bus675	Bus692	1.45	0.565	3.44	120.53	120.97	0.722	1.444
Bus632	Bus671	60.52	6.136	61.77	104.20	109.83	3.799	3.317
Bus680	Bus67l	0.00	0.000	0.00	119.65	123.41	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.311	O.OO0
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.082	0.164
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.722	1.444
Bus633	Bus632	60.70	0.048	62.40	103.96	109.45	0.082	0.188
U2	Bus632	100.00	3.900	100.00	100.00	100.00	2.602	3.069
WTG1	Bus632	100.00	2.237	100.00	100.00	100.00	1.116	O.OO0
Lump9	Bus632	100.00	0.025	100.00	100.00	100.00	0.031	0.064
Bus634	Bus633	62.26	0.048	65.04	103.32	108.14	0.082	0.188
Lump1	Bus634	100.00	0.414	100.00	100.00	100.00	0.708	1.629
Bus671	Bus692	0.00	6.923	0.00	119.65	123.41	4.188	3.477

Table 3.26: Summary of fault currents for all types of faults at each fault location

Bus		**3-Phase Fault**			**Line-to-Ground Fault**			**Line-to-Line Fault**			***Line-to-Line-to-Ground**		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	3.799	-16.279	16.717	3.676	-9.783	10.451	15.224	3.384	15.595	-16.483	-0.267	16.485
Bus633	4.16	4.057	-9.751	10.561	2.850	-6.224	6.846	8.840	3.694	9.580	-9.793	-1.531	9.912
Bus634	0.48	9.829	-19.163	21.536	9.056	-17.726	19.905	16.749	8.616	18.835	12.601	16.692	20.914
Bus671	4.16	1.874	-7.248	7.486	1.413	-4.696	4.904	6.442	1.652	6.651	-6.958	0.022	6.958
Bus675	4.16	2.140	-6.222	6.580	1.536	-4.217	4.488	5.507	1.897	5.825	-6.064	-0.347	6.074
Bus680	4.16	1.438	-5.272	5.465	1.019	-3.294	3.448	4.653	1.263	4.822	-5.022	-0.096	5.023
Bus692	4.16	1.874	-7.248	7.486	1.413	-4.696	4.904	6.442	1.652	6.651	-6.958	0.022	6.958

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer.

3.3.4 Case 3: IEEE 13 Bus with 1*8 MW DG Located at bus 634

In this section IEEE 13 bus is simulated with a DG penetration level of 8 MW centralised. DG is placed at bus 634 and the results of this section are tabulated below

Table 3.27: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.06043	0.17508	0.18522	0.06063	0.17174	0.18213	0.18462	0.38503	0.42700
Bus633	4.160	0.09603	0.22268	0.24250	0.09514	0.21617	0.23617	0.27073	0.55637	0.61874
Bus634	0.480	0.00067	0.00428	0.00433	0.00039	0.00318	0.00321	0.00734	0.01453	0.01628
Bus671	4.160	0.10097	0.33877	0.35350	0.10122	0.33618	0.35109	0.26789	0.80107	0.84468
Bus675	4.160	0.13841	0.37311	0.39796	0.13870	0.37058	0.39569	0.31698	0.83323	0.89148
Bus680	4.160	0.13631	0.45215	0.47225	0.13655	0.44956	0.46984	0.39160	1.16385	1.22796
Bus692	4.160	0.10097	0.33877	0.35350	0.10122	0.33618	0.35109	0.26789	0.80107	0.84468

Table 3.28: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus632	Total	0.00	12.967	0.00	115.21	121.06	9.085	9.085
Bus67l	Bus632	11.83	1.199	17.81	110.15	113.65	0.943	1.163
Bus633	Bus632	7.01	1.859	4.80	115.18	121.32	1.062	0.451
U2	Bus632	100.00	9.864	100.00	100.00	100.00	7.021	7.361
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.081	0.154
Bus680	Bus671	11.83	0.000	17.81	110.15	113.65	0.000	0.000
Lump3	Bus671	100.00	0.644	100.00	100.00	100.00	0.298	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.065	0.119
Bus675	Bus692	12.93	0.499	19.64	110.94	111.90	0.579	1.045
Bus634	Bus633	68.02	1.859	39.67	121.69	127.30	1.062	0.451
Lump4	Bus675	100.00	0.499	100.00	100.00	100.00	0.579	1.045
WTG6	Bus634	100.00	15.760	100.00	100.00	100.00	7.762	0.000
Lump1	Bus634	100.00	0.381	100.00	100.00	100.00	1.444	3.907
Bus692	Bus671	11.83	0.499	17.81	110.15	113.65	0.579	1.045

Table 3.29: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	9.904	0.00	119.70	121.70	6.567	6.567
Bus632	Bus633	29.87	7.920	31.38	111.02	114.36	5.483	6.083
Bus634	Bus633	65.45	1.992	35.70	125.30	128.49	1.086	0.485
Bus671	Bus632	38.17	0.855	43.74	107.52	109.41	0.646	0.820
U2	Bus632	100.00	7.032	100.00	100.00	100.00	4.797	5.186
Lump9	Bus632	100.00	0.045	100.00	100.00	100.00	0.056	0.108
WTG6	Bus634	100.00	16.884	100.00	100.00	100.00	7.870	0.000
Lump1	Bus634	100.00	0.408	100.00	100.00	100.00	1.548	4.199
Bus680	Bus671	38.17	0.000	43.74	107.52	109.41	0.000	0.000
Lump3	Bus671	100.00	0.459	100.00	100.00	100.00	0.200	0.000
Lump7	Bus671	100.00	0.040	100.00	100.00	100.00	0.045	0.084
Bus675	Bus692	39.01	0.356	44.98	108.09	108.15	0.400	0.736
Lump4	Bus675	100.00	0.356	100.00	100.00	100.00	0.400	0.736
Bus692	Bus671	38.17	0.356	43.74	107.52	109.41	0.400	0.736

Table 3.30: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	63.942	0.00	126.10	138.63	35.309	35.309
Bus633	Bus634	72.28	19.066	59.84	112.68	117.90	15.784	29.644
WTG6	Bus634	100.00	45.279	100.00	100.00	100.00	17.577	0.000
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	2.229	5.681
Bus632	Bus633	80.48	2.200	72.83	107.75	111.66	1.821	3.420
Bus671	Bus632	82.82	0.238	78.38	105.80	108.31	0.226	0.461
02	Bus632	100.00	1.953	100.00	100.00	100.00	1.580	2.916
Lump9	Bus632	100.00	0.013	100.00	100.00	100.00	0.024	0.061
Bus680	Bus671	82.82	0.000	78.38	105.80	108.31	0.000	0.000
Lump3	Bus671	100.00	0.128	100.00	100.00	100.00	0.041	0.000
Lump7	Bus671	100.00	0.011	100.00	100.00	100.00	0.019	0.047
Bus675	Bus692	83.04	0.099	78.85	106.18	107.54	0.168	0.414
Lump4	Bus675	100.00	0.099	100.00	100.00	100.00	0.168	0.414
Bus692	Bus671	82.82	0.099	78.38	105.80	108.31	0.168	0.414

Table 3.31: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	6.794	0.00	118.21	119.84	4.651	4.651
Bus632	Bus671	53.77	5.452	57.95	103.90	107.38	3.539	3.146
Bus680	Bus671	0.00	0.000	0.00	118.21	119.84	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.332	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.081	0.156
Bus675	Bus692	1.45	0.565	3.34	119.08	117.54	0.714	1.370
Bus633	Bus632	56.82	0.860	59.95	103.86	107.55	0.472	0.178
U2	Bus632	100.00	4.563	100.00	100.00	100.00	3.035	2.911
Lump9	Bus632	100.00	0.029	100.00	100.00	100.00	0.034	0.061
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.714	1.370
Bus634	Bus633	84.78	0.860	75.25	105.94	110.23	0.472	0.178
WTG6	Bus634	100.00	7.290	100.00	100.00	100.00	3.509	0.000
Lump1	Bus634	100.00	0.176	100.00	100.00	100.00	0.579	1.545
Bus692	Bus671	0.00	0.565	0.00	118.21	119.84	0.714	1.370

Table 3.32: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus675	Total	0.00	6.035	0.00	117.23	117.52	4.276	4.276
Bus692	Bus675	14.04	5.477	12.35	118.40	114.78	3.572	2.960
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.723	1.361
Bus632	Bus671	59.45	4.789	61.88	104.49	105.55	3.204	2.824
Bus680	Bus671	14.04	0.000	12.35	118.40	114.78	0.000	0.000
Lump3	Bus671	100.00	0.641	100.00	100.00	100.00	0.302	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.073	0.140
Bus633	Bus632	62.23	0.756	63.75	104.46	105.72	0.428	0.160
U2	Bus632	100.00	4.009	100.00	100.00	100.00	2.747	2.613
Lump9	Bus632	100.00	0.026	100.00	100.00	100.00	0.030	0.055
Bus634	Bus633	87.03	0.756	77.80	106.47	107.99	0.428	0.160
WTG6	Bus634	100.00	6.405	100.00	100.00	100.00	3.190	0.000
Lump1	Bus634	100.00	0.155	100.00	100.00	100.00	0.522	1.387
Bus671	Bus692	14.04	5.477	12.35	118.40	114.78	3.572	2.960

Table 3.33: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus680	Total	0.00	5.086	0.00	120.42	121.98	3.321	3.321
Bus671	Bus680	25.15	5.086	28.61	112.43	113.56	3.321	3.321
Bus632	Bus671	65.39	4.081	69.95	102.70	105.19	2.526	2.246
Lump3	Bus671	100.00	0.546	100.00	100.00	100.00	0.237	0.000
Lump1	Bus671	100.00	0.048	100.00	100.00	100.00	0.058	0.111
Bus675	Bus692	25.99	0.423	29.98	113.14	111.89	0.510	0.978
Bus633	Bus632	67.68	0.644	71.39	102.67	105.31	0.337	0.127
U2	Bus632	100.00	3.415	100.00	100.00	100.00	2.167	2.078
Lomp9	Bus632	100.00	0.022	100.00	100.00	100.00	0.024	0.043
Lump4	Bus675	100.00	0.423	100.00	100.00	100.00	0.510	0.978
Bus634	Bus633	88.59	0.644	82.33	104.04	107.14	0.337	0.127
WTG6	Bus634	100.00	5.457	100.00	100.00	100.00	2.505	0.000
Lump1	Bus634	100.00	0.132	100.00	100.00	100.00	0.414	1.103
Bus692	Bus67l	25.15	0.423	28.61	112.43	113.56	0.510	0.978

Table 3.34: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	6.794	0.00	118.21	119.84	4.651	4.651
Bus675	Bus692	1.45	0.565	3.34	119.08	117.54	0.714	1.370
Bus632	BUS671	53.77	5.452	57.95	103.90	107.38	3.539	3.146
Bus680	Bus671	0.00	0.000	0.00	118.21	119.84	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.332	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.081	0.156
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.714	1.370
Bus633	Bus632	56.82	0.860	59.95	103.86	107.55	0.472	0.178
U2	Bus632	100.00	4.563	100.00	100.00	100.00	3.035	2.911
Lump9	Bus632	100.00	0.029	100.00	100.00	100.00	0.034	0.061
Bus634	Bus633	84.78	0.860	75.25	105.94	110.23	0.472	0.178
WTG6	Bus634	100.00	7.290	100.00	100.00	100.00	3.509	0.000
Lump1	Bus634	100.00	0.176	100.00	100.00	100.00	0.579	1.545
Bus671	Bns692	0.00	6.234	0.00	118.21	119.84	3.945	3.298

Table 3.35: Summary of fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	kV	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.
Bus632	4.16	4.231	-12.258	12.967	3.501	-8.383	9.085	10.692	3.732	11.325	-12.097	-0.578	12.111
Bus633	4.16	3.922	-9.095	9.904	2.765	-5.957	6.567	7.968	3.471	8.691	-8.984	-1.282	9.075
Bus634	0.48	9.814	-63.184	63.942	12.595	-32.986	35.309	63.044	8.911	63.671	-66.534	0.192	66.534
Bus671	4.16	1.941	-6.511	6.794	1.412	-4.432	4.651	5.656	1.694	5.904	-6.199	-0.020	6.199
Bus675	4.16	2.099	-5.658	6.035	1.507	-4.001	4.276	4.912	1.830	5.242	-5.492	-0.286	5.499
Bus680	4.16	1.468	-4.869	5.086	1.017	-3.161	3.321	4.226	1.279	4.416	-4.610	-0.112	4.611
Bus692	4.16	1.941	-6.511	6.794	1.412	-4.432	4.651	5.656	1.694	5.904	-6.199	-0.020	6.199

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

In this case the fault is after the transformer in the low tertian side so all fault values were observed to be much higher than the rest of the case. On the other hand all the branch currents are reduced.

3.3.5 Case 4: IEEE 13 Bus with 1*8 MW DG Located at bus 671

In this section IEEE 13 bus is simulated with a DG penetration level of 8 MW centralised. DG is placed at bus 671 and the results were tabulated below.

Table 3.36: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.04879	0.16237	0.16954	0.04600	0.15306	0.15983	0.18462	0.38503	0.42700
Bus633	4.160	0.10331	0.23226	0.25420	0.10057	0.22303	0.24465	0.27073	0.55637	0.61874
Bus634	0.480	0.00607	0.01172	0.01320	0.00603	0.01161	0.01309	0.00734	0.01453	0.01628
Bus671	4.160	0.03337	0.19825	0.20104	0.02407	0.16090	0.16269	0.26789	0.80107	0.84468
Bus675	4.160	0.07491	0.23443	0.24611	0.06652	0.19772	0.20861	0.31698	0.83323	0.89148
Bus680	4.160	0.06870	0.31163	0.31912	0.05941	0.27428	0.28064	0.39160	1.16385	1.22796
Bus692	4.160	0.03337	0.19825	0.20104	0.02407	0.16090	0.16269	0.26789	0.80107	0.84468

Table 3.37: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	14.166	0.00	116.44	124.44	9.554	9.554
Bus67l	Bus632	41.18	4.175	32.69	114.94	120.24	2.411	1.224
Bus633	Bus632	0.46	0.121	1.64	115.60	123.42	0.210	0.474
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.888	7.741
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.081	0.162
Bus680	Bus671	41.18	0.000	32.69	114.94	120.24	0.000	0.000
WTG3	Bus671	100.00	3.371	100.00	100.00	100.00	1.677	0.000
Lump3	Bus671	100.00	0.435	100.00	100.00	100.00	0.177	0.000
Lump7	Bus671	100.00	0.038	100.00	100.00	100.00	0.057	0.125
Bus675	Bus692	41.96	0.337	34.25	115.67	118.32	0.501	1.099
Bus634	Bus633	4.42	0.121	8.55	113.18	120.00	0.210	0.474
Lump4	Bus675	100.00	0.337	100.00	100.00	100.00	0.501	1.099
Lamp1	Bus634	100.00	1.047	100.00	100.00	100.00	1.823	4.109
Bus692	Bus671	41.18	0.337	32.69	114.94	120.24	0.501	1.099

Table 3.38: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	9.448	0.00	118.69	120.23	6.448	6.448
Bus632	Bus633	35.17	9.327	33.98	110.76	114.31	6.235	5.973
Bus634	Bus633	3.99	0.121	6.99	116.10	116.97	0.213	0.476
Bus671	Bus632	62.13	2.772	55.71	109.91	111.66	1.614	0.805
U2	Bus632	100.00	6.550	100.00	100.00	100.00	4.592	5.092
Lump9	Bus632	100.00	0.042	100.00	100.00	100.00	0.054	0.106
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.844	4.123
Bus680	Bus671	62.13	0.000	55.71	109.91	111.66	0.000	0.000
WTG3	Bus671	100.00	2.238	100.00	100.00	100.00	1.127	0.000
Lump3	Bus671	100.00	0.289	100.00	100.00	100.00	0.119	0.000
Lump7	Bus671	100.00	0.025	100.00	100.00	100.00	0.038	0.082
Bus675	Bus692	62.68	0.224	56.79	110.43	110.36	0.332	0.723
Lump4	Bus675	100.00	0.224	100.00	100.00	100.00	0.332	0.723
Bus692	Bus671	62.13	0.224	55.71	109.91	111.66	0.332	0.723

Table 3.39: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	20.992	0.00	104.02	103.35	19.530	19.530
Bus633	Bus634	75.45	19.901	67.53	105.31	105.06	17.812	16.397
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.724	3.142
Bus632	Bus633	84.01	2.296	78.57	103.08	103.80	2.055	1.892
Bus671	Bus632	90.72	0.683	85.72	102.91	103.06	0.537	0.255
U2	Bus632	100.00	1.613	100.00	10000	100.00	1.509	1.613
Lump9	Bus632	100.00	0.010	100.00	100.00	100.00	0.017	0.034
Bus680	Bus671	90.72	0.000	85.72	102.91	103.06	0.000	0.000
WTG3	Bus671	100.00	0.551	100.00	100.00	100.00	0.378	0.000
Lump3	Bus671	100.00	0.071	100.00	100.00	100.00	0.040	o.ooo
Lump7	Bus671	100.00	0.006	100.00	100.00	100.00	0.012	0.026
Bus675	Bus692	90.85	0.055	86.05	103.10	102.64	0.107	0.229
Lump4	Bus675	100.00	0.055	100.00	100.00	100.00	0.107	0.229
Bus692	Bus671	90.72	0.055	85.72	102.91	103.06	0.107	0.229

Table 3.40: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus671	Total	0.00	11.947	0.00	131.27	137.61	5.980	5.980
Bus632	Bus671	49.79	5.048	57.85	106.50	113.55	2.868	4.045
Bus680	Bus671	0.00	0.000	0.00	131.27	137.61	0.000	0.000
WTG3	Bus671	100.00	5.658	100.00	100.00	100.00	2.089	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.220	0.000
Lump7	Bus67l	100.00	0.063	100.00	100.00	100.00	0.086	0.200
Bus675	Bus692	1.45	0.565	3.88	132.05	134.63	0.757	1.761
Bus633	Bus632	50.00	0.061	58.60	106.19	113.06	0.094	0.229
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.740	3.742
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.078
Lmnp4	Bus675	100.00	0.565	100.00	100.00	100.00	0.757	1.761
Bus634	Bus633	51.98	0.061	61.62	105.31	111.34	0.094	0.229
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.818	1.986
Bus692	Bus671	0.00	0.565	0.00	131.27	137.61	0.757	1.761

Table 3.41: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus675	Total	0.00	9.759	0.00	129.44	131.03	5.354	5.354
Bus692	Bus675	23.57	9.195	15.83	130.48	127.96	4.611	3.707
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.761	1.704
Bus632	Bus671	59.97	4.078	62.88	107.44	110.01	2.527	3.536
Bus680	Bus671	23.57	0.000	15.83	130.48	127.96	0.000	0.000
WTG3	Bus671	100.00	4.571	100.00	100.00	100.00	1.850	0.000
Lump3	Bus671	100.00	0.589	100.00	100.00	100.00	0.195	0.000
Lump7	Bus671	100.00	0.051	100.00	100.00	100.00	0.075	0.175
Bus633	Bus632	60.16	0.049	63.54	107.13	109.63	0.083	0.200
U2	Bus632	100.00	4.004	100.00	100.00	100.00	2.414	3.272
Lump9	Bus632	100.00	0.026	100.00	100.00	100.00	0.031	0.068
Bus634	Bus633	61.76	0.049	66.26	106.20	108.29	0.083	0.200
Lump1	Bus634	100.00	0.425	100.00	100.00	100.00	0.717	1.737
Bus671	Bus692	23.57	9.195	15.83	130.48	127.96	4.611	3.707

Table 3.42: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	7.526	0.00	129.51	134.04	3.947	3.947
Bus671	Bus680	37.21	7.526	34.01	119.09	122.99	3.947	3.947
Bus632	Bus671	68.36	3.180	72.13	104.08	108.59	1.893	2.670
WTG3	Bus671	100.00	3.565	100.00	100.00	100.00	1.379	0.000
Lump3	Bus671	100.00	0.460	100.00	100.00	100.00	0.145	0.000
Lump7	Bus671	100.00	0.040	100.00	100.00	100.00	0.057	0.132
Bus675	Bus692	37.99	0.356	35.44	119.81	120.94	0.499	1.163
Bus633	Bus632	68.51	0.038	72.62	103.89	108.28	0.062	0.151
U2	Bus632	100.00	3.122	100.00	100.00	100.00	1.809	2.470
Lump9	Bus632	100.00	0.020	100.00	100.00	100.00	0.023	0.052
Lump4	Bus675	100.00	0.356	100.00	100.00	100.00	0.499	1.163
Bus634	Bus633	69.76	0.038	74.64	103.37	107.19	0.062	0.151
Lump1	Bus634	100.00	0.331	100.00	100.00	100.00	0.540	1.311
Bus692	Bus671	37.21	0.356	34.01	119.09	122.99	0.499	1.163

Table 3.43: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	11.947	0.00	131.27	137.61	5.980	5.980
Bus675	Bus692	1.45	0.565	3.88	132.05	134.63	0.757	1.761
Bus632	Bus671	49.79	5.048	57.85	106.50	113.55	2.868	4.045
Bus680	Bus671	0.00	0.000	0.00	131.27	137.61	0.000	0.000
WTG3	Bus67l	100.00	5.658	100.00	100.00	100.00	2.089	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.220	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.086	0.200
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.757	1.761
Bus633	Bus632	50.00	0.061	58.60	106.19	113.06	0.094	0.229
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.740	3.742
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.078
Bus634	Bus633	51.98	0.061	61.62	105.31	111.34	0.094	0.229
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.818	1.986
Bus671	Bus692	0.00	11.381	0.00	131.27	137.61	5.227	4.239

Table 3.44: Summary of fault currents for all types of faults at each fault location

Bus		**3-Phase Fault**			**Line-to-Ground Fault**			**Line-to-Line Fault**			***Line-to-Line-to-Ground**		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	4.076	-13.567	14.166	3.540	-8.874	9.554	12.096	3.635	12.630	-13.451	-0.474	13.459
Bus633	4.16	3.840	-8.633	9.448	2.739	-5.838	6.448	7.611	3.408	8.339	-8.612	-1.248	8.702
Bus634	0.48	9.646	-18.645	20.992	8.921	-17.374	19.530	16.211	8.405	18.260	12.091	16.463	20.426
Bus671	4.16	1.983	-11.781	11.947	1.614	-5.758	5.980	11.294	1.806	11.437	-11.729	-0.142	11.730
Bus675	4.16	2.971	-9.296	9.759	1.824	-5.034	5.354	8.695	2.846	9.149	-9.188	-1.266	9.275
Bus680	4.16	1.620	-7.350	7.526	1.124	-3.784	3.947	6.776	1.482	6.936	-7.112	-0.304	7.118
Bus692	4.16	1.983	-11.781	11.947	1.614	-5.758	5.980	11.294	1.806	11.437	-11.729	-0.142	11.730

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

3.3.6 Case 5: IEEE 13 Bus with 1*8 MW DG Located at bus 675

In this section IEEE 13 bus is simulated with a DG penetration level of 8 MW centralised. DG is placed at bus 675 and the results are tabulated below.

Table 3.45: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.05233	0.16409	0.17223	0.05072	0.15572	0.16377	0.18462	0.38503	0.42700
Bus633	4.160	0.10682	0.23397	0.25720	0.10524	0.22567	0.24901	0.27073	0.55637	0.61874
Bus634	0.480	0.00611	0.01175	0.01324	0.00609	0.01164	0.01314	0.00734	0.01453	0.01628
Bus671	4.160	0.04708	0.20570	0.21101	0.04224	0.17229	0.17740	0.26789	0.80107	0.84468
Bus675	4.160	0.04045	0.20995	0.21381	0.02833	0.16866	0.17102	0.31698	0.83323	0.89148
Bus680	4.160	0.08242	0.31907	0.32954	0.07758	0.28567	0.29602	0.39160	1.16385	1.22796
Bus692	4.160	0.04708	0.20570	0.21101	0.04224	0.17229	0.17740	0.26789	0.80107	0.84468

Table 3.46: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus632	Total	0.00	13.945	0.00	116.57	123.46	9.465	9.465
Bus67l	Bus632	38.74	3.927	31.36	115.16	118.76	2.287	1.212
Bus633	Bus632	0.46	0.121	1.63	115.73	122.46	0.210	0.470
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.910	7.669
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.081	0.160
Bus680	Bus671	38.74	0.000	31.36	115.16	118.76	0.000	0.000
Lump3	Bus671	100.00	0.449	100.00	100.00	100.00	0.187	0.000
Lump7	Bus671	100.00	0.039	100.00	100.00	100.00	0.057	0.124
Bus675	Bus692	46.42	3.439	36.50	116.01	118.63	2.043	1.088
Bus634	Bus633	4.42	0.121	8.51	113.33	119.12	0.210	0.470
WTG5	Bus675	100.00	3.125	100.00	100.00	100.00	1.555	0.000
Lump4	Bus675	100.00	0.316	100.00	100.00	100.00	0.489	1.088
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.816	4.071
Bus692	Bus671	38.74	3.439	31.36	115.16	118.76	2.043	1.088

Table 3.47: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	9.338	0.00	118.72	119.60	6.405	6.405
Bus632	Bus633	34.76	9.217	33.75	110.86	1)3.77	6.193	5.933
Bus634	Bas633	3.99	0.121	6.97	116.15	116.39	0.212	0.473
Bus67l	Bus632	60.09	2.618	54.63	110.08	110.81	1.535	0.799
U2	Bus632	100.00	6.576	100.00	100.00	100.00	4.619	5.058
Lump9	Bus632	100.00	0.042	100.00	100.00	100.00	0.054	0.106
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.839	4.096
Bus680	Bus671	60.09	0.000	54.63	110.08	110.81	0.000	0.000
Lump3	Bus671	100.00	0.299	100.00	100.00	100.00	0.126	0.000
Lump?	Bus671	100.00	0.026	100.00	100.00	100.00	0.038	0.082
Bus675	Bus692	65.51	2.293	58.14	110.64	110.64	1.371	0.718
WTG5	Bus675	100.00	2.084	100.00	100.00	100.00	1.048	0.000
Lump4	Bus675	100.00	0.211	100.00	100.00	100.00	0.324	0.718
Bus692	Bus671	60.09	2.293	54.63	110.08	110.81	1.371	0.718

Table 3.48: 3-phase & single line to ground fault currents when fault is at bus 643

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	20.931	0.00	104.06	103.23	19.487	19.487
Bus633	Bus634	75.21	19.840	67.37	105.35	104.93	17.770	16.361
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.722	3.135
Bus632	Bus633	83.75	2.289	78.39	103.13	103.68	2.050	1.888
Bus671	Bus632	90.12	0.650	85.28	102.98	102.83	0.513	0.254
U2	Bus632	100.00	1.633	100.00	100.00	100.00	1.525	1.609
Lump9	Bus632	100.00	0.011	100.00	100.00	100.00	0.018	0.034
Bus680	Bus671	90.12	0.000	85.28	102.98	102.83	0.000	0.000
Lump3	Bus671	100.00	0.074	100.00	100.00	100.00	0.042	0.000
Lump7	Bus671	100.00	0.006	100.00	100.00	100.00	0.012	0.026
Bus675	Bus692	91.43	0.569	86.43	103.16	102.76	0.458	0.228
WTG5	Bus675	100.00	0.518	100.00	100.00	100.00	0.353	0.000
Lump4	Bus675	100.00	0.052	100.00	100.00	100.00	0.105	0.228
Bus692	Bus671	90.12	0.569	85.28	102.98	102.83	0.458	0.228

Table 3.49: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	11.382	0.00	131.36	134.53	5.849	5.849
Bus632	Bus671	49.79	5.048	57.66	106.96	112.28	2.910	3.956
Bus680	Bus67I	0.00	0.000	0.00	131.36	134.53	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.230	o.ooo
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.196
Bus675	Bus692	14.32	5.587	8.51	132.38	133.91	2.643	1.722
Bus633	Bus632	50.00	0.061	58.39	106.65	111.81	0.094	0.224
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.782	3.660
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.076
WTG5	Bus675	100.00	5.077	100.00	100.00	100.00	1.912	0.000
Lump4	Bus675	100.00	0.513	100.00	100.00	100.00	0.730	1.722
Bus634	Bus633	51.98	0.061	61.39	105.75	110.19	0.094	0.224
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.812	1.943
Bus692	Bus671	0.00	5.587	0.00	131.36	134.53	2.643	1.722

Table 3.50: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus675	Total	0.00	11.233	0.00	130.76	137.90	5.666	5.666
Bus692	Bus675	13.23	5.163	11.48	131.65	132.18	2.867	3.923
WTG5	Bus675	100.00	5.658	100.00	100.00	100.00	2.092	0.000
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.772	1.803
Bus632	Bus67I	55.59	4.470	61.47	107.42	111.60	2.596	3.742
Bus680	Bus671	13.23	0.000	11.48	131.65	132.18	0.000	0.000
Lump3	Bus671	100.00	0.646	100.00	100.00	100.00	0.196	0.000
Lump7	Bus671	100.00	0.056	100.00	100.00	100.00	0.079	0.185
Bus633	Bus632	55.79	0.054	62.17	107.09	111.17	0.087	0.212
U2	Bus632	100.00	4.389	100.00	100.00	100.00	2.479	3.463
Lump9	Bus632	100.00	0.028	100.00	100.00	100.00	0.032	0.072
Bus634	Bus633	57.56	0.054	65.01	106.15	109.68	0.087	0.212
Lump1	Bus634	100.00	0.466	100.00	100.00	100.00	0.751	1.838
Bus671	Bus692	13.23	5.163	11.48	131.65	132.18	2.867	3.923

Table 3.51: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	7.288	0.00	129.58	132.08	3.889	3.889
Bus671	Bus680	36.04	7.288	33.51	119.34	121.34	3.889	3.889
Bus632	Bus671	67.83	3.232	71.80	104.37	107.89	1.935	2.631
Lump3	Bus671	100.00	0.467	100.00	100.00	100.00	0.153	0.000
Lump7	Bus671	100.00	0.041	100.00	100.00	100.00	0.057	0.130
Bus675	Bus692	43.72	3.577	37.72	120.05	120.81	1.757	1.145
Bus633	Bus632	67.97	0.039	72.29	104.18	107.59	0.062	0.149
U2	Bus632	100.00	3.173	100.00	100.00	100.00	1.850	2.434
Lump9	Bus632	100.00	0.020	100.00	100.00	100.00	0.024	0.051
WTG5	Bus675	100.00	3.251	100.00	100.00	100.00	1.272	0.000
Lump4	Bus675	100.00	0.328	100.00	100.00	100.00	0.486	1.145
Bus634	Bus633	69.24	0.039	74.30	103.65	106.56	0.062	0.149
Lump1	Bus634	100.00	0.337	100.00	100.00	100.00	0.540	1.292
Bus692	Bus67l	36.04	3.577	33.51	119.34	121.34	1.757	1.145

Table 3.52: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	To(al	0.00	11.382	0.00	131.36	134.53	5.849	5.849
Bus675	Bus692	14.32	5.587	8.51	132.38	133.91	2.643	1.722
Bus632	Bus671	49.79	5.048	57.66	106.96	112.28	2.910	3.956
Bus680	Bus671	0.00	0.000	0.00	131.36	134.53	0.000	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.230	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.196
WTG5	Bus675	100.00	5.077	100.00	100.00	100.00	1.912	0.000
Lump4	Bus675	100.00	0.513	100.00	100.00	100.00	0.730	1.722
Bus633	Bus632	50.00	0.061	58.39	106.65	111.81	0.094	0.224
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.782	3.660
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.076
Bus634	Bus633	51.98	0.061	61.39	105.75	110.19	0.094	0.224
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.812	1.943
Bus671	Bus692	0.00	5.830	0.00	131.36	134.53	3.220	4.147

Table 3.53: Summary of Fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	kV	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.
Bus632	4.16	4.237	-13.286	13.945	3.577	-8.763	9.465	11.784	3.797	12.381	-13.150	-0.632	13.165
Bus633	4.16	3.878	-8.495	9.338	2.749	-5.785	6.405	7.462	3.443	8.218	-8.469	-1.282	8.565
Bus634	0.48	9.658	-18.570	20.931	8.927	-17.322	19.487	16.132	8.414	18.195	12.015	16.468	20.385
Bus671	4.16	2.540	-11.095	11.382	1.696	-5.597	5.849	10.424	2.463	10.711	-10.868	-0.761	10.895
Bus675	4.16	2.125	-11.030	11.233	1.719	-5.399	5.666	10.637	1.932	10.811	-11.106	-0.384	11.113
Bus680	4.16	1.823	-7.057	7.288	1.158	-3.713	3.889	6.429	1.701	6.650	-6.771	-0.512	6.790
Bus692	4.16	2.540	-11.095	11.382	1.696	-5.597	5.849	10.424	2.463	10.711	-10.868	-0.761	10.895

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

3.3.7 Case 5: IEEE 13 Bus with 1*8 MW DG Located at bus 680

In this section IEEE 13 bus is simulated with a DG penetration level of 8 MW centralised. DG is placed at bus 680 and the results are tabulated below.

Table 3.54: Positive, Negative and Zero Sequence Impedances and seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.05212	0.16719	0.17512	0.05033	0.16025	0.16796	0.18462	0.38503	0.42700
Bus633	4.160	0.10660	0.23704	0.25991	0.10484	0.23016	0.25291	0.27073	0.55637	0.61874
Bus634	0.480	0.00611	0.01178	0.01327	0.00609	0.01170	0.01319	0.00734	0.01453	0.01628
Bus671	4.160	0.04567	0.21793	0.22266	0.03986	0.19013	0.19426	0.26789	0.80107	0.84468
Bus675	4.160	0.08658	0.25389	0.26825	0.08141	0.22660	0.24078	0.31698	0.83323	0.89148
Bus680	4.160	0.03449	0.22783	0.23042	0.02413	0.17975	0.18136	0.39160	1.16385	1.22796
Bus692	4.160	0.04567	0.21793	0.22266	0.03986	0.19013	0.19426	0.26789	0.80107	0.84468

Table 3.55: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	13.715	0.00	115.83	123.35	9.380	9.380
Bus671	Bus632	36.58	3.709	30.26	114.02	118.74	2.181	1.201
Bus633	Bus632	0.46	0.121	1.62	115.01	122.36	0.209	0.466
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.939	7.600
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.081	0.159
Bus680	Bus671	50.63	2.842	37.24	116.08	120.79	1.413	0.000
Lump3	Bus671	100.00	0.466	100.00	100.00	100.00	0.199	0.000
Lump7	Bus671	100.00	0.041	100.00	100.00	100.00	0.058	0.123
Bus675	Bus692	37.39	0.361	31.83	114.77	116.86	0.513	1.079
Bus634	Bus633	4.42	0.121	8.48	112.68	119.05	0.209	0.466
WTG2	Bus680	100.00	2.842	100.00	100.00	100.00	1.413	0.000
Lump4	Bus675	100.00	0.361	100.00	100.00	100.00	0.513	1.079
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.809	4.034
Bus692	Bus671	36.58	0.361	30.26	114.02	118.74	0.513	1.079

Table 3.56: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus633	Total	0.00	9.241	0.00	118.22	119.57	6.368	6.368
Bus632	Bus633	34.39	9.120	33.55	110.43	113.79	6.157	5.899
Bus634	Bus633	3.99	0.121	6.95	115.69	116.39	0.212	0.470
Bus67l	Bus632	58.54	2.488	53.78	109.38	110.92	1.469	0.795
U2	Bus632	100.00	6.617	100.00	100.00	100.00	4.654	5.029
Lump9	Bus632	100.00	0.043	100.00	100.00	100.00	0.054	0.105
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.834	4.072
Bus680	Bus671	67.90	1.907	58.48	110.71	112.08	0.955	0.000
Lump3	Bus671	100.00	0.313	100.00	100.00	100.00	0.134	0.000
Lump7	Bus671	100.00	0.027	100.00	100.00	100.00	0.039	0.081
Bus675	Bus692	59.12	0.242	54.87	109.90	109.65	0.341	0.714
WTG2	Bus680	100.00	1.907	100.00	100.00	100.00	0.955	0.000
Lump4	Bus675	100.00	0.242	100.00	100.00	100.00	0.341	0.714
Bus692	Bus671	58.54	0.242	53.78	109.38	110.92	0.341	0.714

Table 3.57: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus634	Total	0.00	20.880	0.00	103.96	103.27	19.451	19.451
Bus633	Bus634	75.02	19.789	67.24	105.23	104.96	17.735	16.331
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.721	3.130
Bus632	Bus633	83.53	2.283	78.23	103.02	103.71	2.046	1.884
Bus671	Bus632	89.65	0.623	84.93	102.79	102.91	0.492	0.254
U2	Bus632	100.00	1.657	100.00	100.00	100.00	1.543	1.606
Lump9	Bus632	100.00	0.011	100.00	100.00	100.00	0.018	0.034
Bus680	Bus671	92.01	0.477	86.52	103.18	103.20	0.323	0.000
Lump3	Bus671	100.00	0.078	100.00	100.00	100.00	0.046	0.000
Lump7	Bus671	100.00	0.007	100.00	100.00	100.00	0.013	0.026
Bus675	Bus692	89.80	0.061	85.27	102.98	102.50	0.111	0.228
WTG2	Bus680	100.00	0.477	100.00	100.00	100.00	0.323	0.000
Lump4	Bus675	100.00	0.061	100.00	100.00	100.00	0.111	0.228
Bus692	Bus671	89.65	0.061	84.93	102.79	102.91	0.111	0.228

Table 3.58: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus671	Total	0.00	10.787	0.00	129.08	133.81	5.720	5.720
Bus632	Bus671	49.79	5.048	57.49	106.16	112.15	2.959	3.869
Bus680	Bus671	22.00	4.449	8.48	131.74	136.89	1.714	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.241	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.192
Bus675	Bus692	1.45	0.565	3.77	129.87	130.95	0.748	1.684
Bus633	Bus632	50.00	0.061	58.21	105.86	111.69	0.093	0.219
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.833	3.580
Lump 9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.075
WTG2	Bus680	100.00	4.449	100.00	100.00	100.00	1.714	0.000
Lump4	Bus67S	100.00	0.565	100.00	100.00	100.00	0.748	1.684
Bus634	Bus633	51.98	0.061	61.19	105.03	110.11	0.093	0.219
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.805	1.900
Bus692	Bus671	0.00	0.565	0.00	129.08	133.81	0.748	1.684

Table 3.59: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus675	Total	0.00	8.954	0.00	127.37	128.19	5.145	5.145
Bus692	Bus675	21.51	8.392	15.16	128.44	125.17	4.410	3.562
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.754	1.638
Bus632	Bus671	59.16	4.144	62.36	106.98	109.02	2.619	3.399
Bus680	Bus671	38.61	3.653	21.81	130.84	127.71	1.525	0.000
Lump3	Bus671	100.00	0.599	100.00	100.00	100.00	0.215	0.000
Lump7	Bus671	100.00	0.052	100.00	100.00	100.00	0.075	0.168
Bus633	Bus632	59.35	0.050	63.01	106.68	108.66	0.082	0.193
U2	Bus632	100.00	4.068	100.00	100.00	100.00	2.507	3.145
Lump9	Bus632	100.00	0.026	100.00	100.00	100.00	0.031	0.066
WTG2	Bus680	100.00	3.653	100.00	100.00	100.00	1.525	0.000
Bus634	Bus633	60.98	0.050	65.70	105.81	107.42	0.082	0.193
Lump1	Bus634	100.00	0.432	100.00	100.00	100.00	0.710	1.669
Bus671	Bus692	21.51	8.392	15.16	128.44	125.17	4.410	3.562

Table 3.60: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	10.423	0.00	137.59	143.44	4.408	4.408
Bus671	Bus680	24.01	4.856	29.42	122.82	127.46	2.685	4.408
WTG2	Bus680	100.00	5.658	100.00	100.00	100.00	1.739	0.000
Bus632	Bus671	61.83	3.836	70.48	105.05	110.23	1.956	2.981
Lump3	Bus671	100.00	0.554	100.00	100.00	100.00	0.140	0.000
Lump7	Bus671	100.00	0.048	100.00	100.00	100.00	0.061	0.148
Bus675	Bus692	24.87	0.430	30.95	123.55	125.18	0.540	1.298
Bus633	Bus632	62.00	0.046	71.02	104.83	109.87	0.068	0.169
U2	Bus632	100.00	3.766	100.00	100.00	100.00	1.865	2.759
Lump9	Bus632	100.00	0.024	100.00	100.00	100.00	0.025	0.058
Lump4	Bus675	100.00	0.430	100.00	100.00	100.00	0.540	1.298
Bus634	Bus633	63.50	0.046	73.19	104.21	108.62	0.068	0.169
Lump1	Bus634	100.00	0.400	100.00	100.00	100.00	0.586	1.464

Table 3.61: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	10.787	0.00	129.08	133.81	5.720	5.720
Bus675	Bus692	1.45	0.565	3.77	129.87	130.95	0.748	1.684
Bus632	Bus671	49.79	5.048	57.49	106.16	112.15	2.959	3.869
Bus680	Bus671	22.00	4.449	8.48	131.74	136.89	1.714	0.000
Lump3	Bus67l	100.00	0.730	100.00	100.00	100.00	0.241	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.192
Lump4	Bus675	100.00	0.565	100.00	100.00	100.00	0.748	1.684
Bus633	Bus632	50.00	0.061	58.21	105.86	111.69	0.093	0.219
U2	Bus632	100.00	4.956	100.00	100.00	100.00	2.833	3.580
Lump9	Bus632	100.00	0.032	100.00	100.00	100.00	0.035	0.075
WTG2	Bus680	100.00	4.449	100.00	100.00	100.00	1.714	0.000
Bus634	Bus633	51.98	0.061	61.19	105.03	110.11	0.093	0.219
Lump1	Bus634	100.00	0.526	100.00	100.00	100.00	0.805	1.900
Bus671	Bus692	0.00	10.222	0.00	129.08	133.81	4.977	4.055

Table 3.62: Summary of Fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	4.082	-13.093	13.715	3.506	-8.701	9.380	11.572	3.621	12.125	-12.946	-0.459	12.954
Bus633	4.16	3.790	-8.428	9.241	2.714	-5.761	6.368	7.390	3.345	8.112	-8.400	-1.187	8.484
Bus634	0.48	9.607	-18.539	20.880	8.891	-17.301	19.451	16.101	8.359	18.141	11.987	16.413	20.325
Bus671	4.16	2.212	-10.557	10.787	1.605	-5.490	5.720	9.766	2.047	9.978	-10.240	-0.339	10.245
Bus675	4.16	2.890	-8.474	8.954	1.782	-4.827	5.145	7.715	2.697	8.173	-8.245	-1.101	8.318
Bus680	4.16	1.560	-10.306	10.423	1.214	-4.237	4.408	10.000	1.438	10.103	-10.296	-0.283	10.300
Bus692	4.16	2.212	-10.557	10.787	1.605	-5.490	5.720	9.766	2.047	9.978	-10.240	-0.339	10.245

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

3.3.8 Case 7: IEEE 13 Bus with 4*2 MW DG's Distributed at Different Locations in the Network

In this section IEEE 13 bus is simulated with a total DG penetration level of 8 MW decentralised DG's which are placed in the following configuration

- 1*2MW DG placed at bus 632
- 2*2MW DG placed at bus 671
- 1*2MW DG placed at bus 675

Fig. 3.4 below illustrates the configuration of case 7.

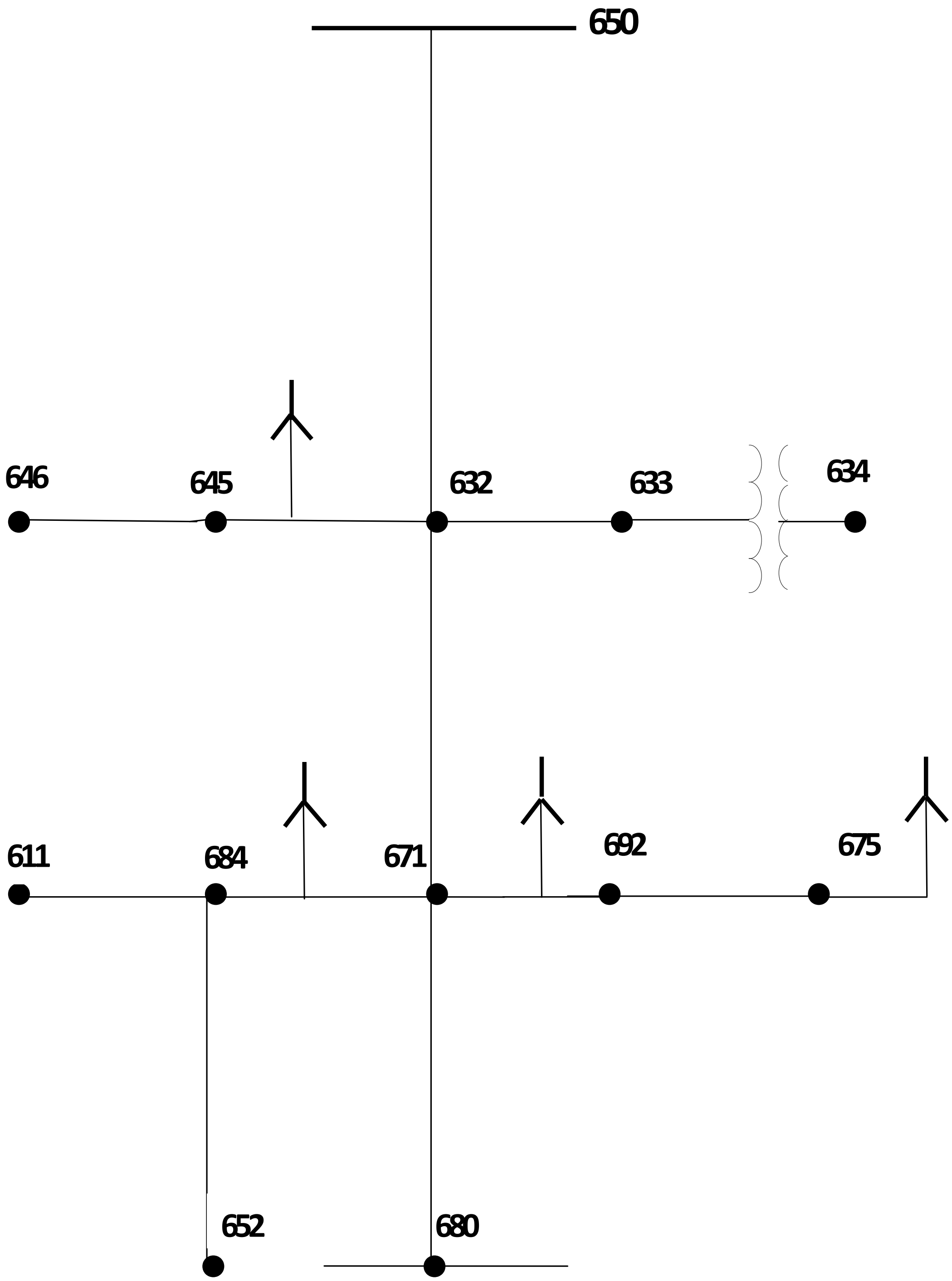

Fig.3.4: configuration used in case 7

Table 3.63: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.04316	0.15458	0.16049	0.03816	0.14111	0.14618	0.18462	0.38503	0.42700
Bus633	4.160	0.09774	0.22452	0.24488	0.09283	0.21116	0.23066	0.27073	0.55637	0.61874
Bus634	0.480	0.00600	0.01163	0.01309	0.00594	0.01146	0.01291	0.00734	0.01453	0.01628
Bus671	4.160	0.04120	0.21808	0.22194	0.03155	0.18164	0.18436	0.26789	0.80107	0.84468
Bus675	4.160	0.06783	0.24547	0.25467	0.05585	0.20703	0.21443	0.31698	0.83323	0.89148
Bus680	4.160	0.07654	0.33146	0.34018	0.06688	0.29501	0.30250	0.39160	1.16385	1.22796
Bus692	4.160	0.04120	0.21808	0.22194	0.03155	0.18164	0.18436	0.26789	0.80107	0.84468

Table 3.64: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	14.965	0.00	117.41	126.47	9.859	9.859
Bus671	Bus632	35.51	3.600	29.73	114.89	120.84	2.082	1.263
Bus633	Bus632	0.46	0.121	1.68	116.52	125.39	0.213	0.489
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.801	7.988
WTG7	Bus632	100.00	1.414	100.00	100.00	100.00	0.735	0.000
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.082	0.167
Bus680	Bus671	35.51	0.000	29.73	114.89	120.84	0.000	0.000
WTG5	Bus67l	100.00	0.921	100.00	100.00	100.00	0.446	0.000
WTG6	Bus671	100.00	0.921	100.00	100.00	100.00	0.446	0.000
Lump3	Bus671	100.00	0.475	100.00	100.00	100.00	0.188	0.000
Lump7	Bus671	100.00	0.041	100.00	100.00	100.00	0.059	0.129
Bus675	Bus692	38.29	1.246	32.35	115.69	119.35	0.944	1.134
Bus634	Bus633	4.42	0.121	8.68	113.95	121.76	0.213	0.489
WTG4	Bus675	100.00	0.889	100.00	100.00	100.00	0.428	0.000
Lump4	Bus675	100.00	0.359	100.00	100.00	100.00	0.517	1.134
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.848	4.240
Bus692	Bus671	35.51	1.246	29.73	114.89	120.84	0.944	1.134

Table 3.65: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	9.808	0.00	119.43	121.42	6.586	6.586
Bus632	Bus633	36.53	9.687	34.71	111.26	115.25	6.371	6.101
Bus634	Bus633	3.99	0.121	7.05	116.74	118.02	0.215	0.486
Bus671	Bus632	59.29	2.349	54.25	109.80	111.82	1.379	0.822
U2	Bus632	100.00	6.436	100.00	100.00	100.00	4.485	5.201
WTG7	Bus632	100.00	0.923	100.00	100.00	100.00	0.489	0.000
Lump9	Bus632	100.00	0.041	100.00	100.00	100.00	0.054	0109
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.861	4.211
Bus680	Bus67l	59.29	0.000	54.25	109.80	111.82	0.000	0.000
WTG5	Bus671	100.00	0.601	100.00	100.00	100.00	0.297	0.000
WTG6	Bus67l	100.00	0.601	100.00	100.00	100.00	0.297	0.000
Lump3	Bus671	100.00	0.310	100.00	100.00	100.00	0.125	0.000
Lump7	Bus671	100.00	0.027	100.00	100.00	100.00	0.039	0.084
Bus675	Bus692	61.22	0.813	56.02	110.35	110.80	0.623	0.738
WTG4	Bus675	100.00	0.580	100.00	100.00	100.00	0.284	0.000
Lump4	Bus675	100.00	0.234	100.00	100.00	100.00	0.338	0.738
Bus692	Bus671	59.29	0.813	54.25	109.80	111.82	0.623	0.738

Table 3.66: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	21.178	0.00	104.10	103.51	19.664	19.664
Bus633	Bus634	76.15	20.087	68.02	105.41	105.24	17.941	16.509
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.728	3.164
Bus632	Bus633	84.79	2.318	79.14	103.16	103.97	2.070	1.905
Bus671	Bus632	90.31	0.562	85.45	102.83	103.04	0.451	0.257
U2	Bus632	100.00	1.540	100.00	100.00	100.00	1.452	1.624
WTG7	Bus632	100.00	0.221	100.00	100.00	100.00	0.162	0.000
Lump9	Bus632	100.00	0.010	100.00	100.00	100.00	0.017	0.034
Bus680	Bus671	90.31	0.000	85.45	102.83	103.04	0.000	0.000
WTG5	Bus671	100.00	0.144	100.00	100.00	100.00	0.098	0.000
WTG6	Bus671	100.00	0.144	100.00	100.00	100.00	0.098	0.000
Lump3	Bus671	100.00	0.074	100.00	100.00	100.00	0.041	0.000
Lump7	Bus671	100.00	0.006	100.00	100.00	100.00	0.012	0.026
Bus675	Bus692	90.76	0.195	86.01	103.02	102.71	0.201	0.230
WTG4	Bus675	100.00	0.139	100.00	100.00	100.00	0.094	0.000
Lump4	Bus675	100.00	0.056	100.00	100.00	100.00	0.107	0.230
Bus692	Bus671	90.31	0.195	85.45	102.83	103.04	0.201	0.230

Table 3.67: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	10.822	0.00	128.76	134.68	5.773	5.773
Bus632	Bus67l	52.92	5.366	58.83	106.03	112.84	3.069	3.905
Bus680	Bus671	0.00	0.000	0.00	128.76	134.68	0.000	0.000
WTG5	Bus671	100.00	1.414	100.00	100.00	100.00	0.565	0.000
WTG6	Bus671	100.00	1.414	100.00	100.00	100.00	0.565	0.000
Lump3	Bus67I	100.00	0.730	100.00	10000	100.00	0.237	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.193
Bus675	Bus692	4.91	1.914	5.10	129.59	132.45	1.285	1.700
Bus633	Bus632	53.13	0.057	59.55	105.73	112.37	0.092	0.221
U2	Bus632	100.00	4.644	100.00	100.00	100.00	2.692	3.613
WTG7	Bus632	100.00	0.666	100.00	100.00	100.00	0.261	0.000
Lump9	Bus632	100.00	0.030	100.00	100.00	100.00	0.035	0.075
WTG4	Bus675	100.00	1.365	100.00	100.00	100.00	0.541	0.000
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.744	1.700
Bus634	Bus633	54.99	0.057	62.49	104.90	110.73	0.092	0.221
Lump1	Bus634	100.00	0.493	100.00	100.00	100.00	0.794	1.918
Bus692	Bus671	0.00	1.914	0.00	128.76	134.68	1.285	1.700

Table 3.68: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus675	Total	0.00	9.431	0.00	127.30	131.45	5.301	5.301
Bus692	Bus675	19.22	7.500	14.13	128.44	127.65	3.982	3.670
WTG4	Bus675	100.00	1.414	100.00	100.00	100.00	0.600	0.000
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.759	1.687
Bus632	Bus671	60.82	4.514	63.26	106.84	110.24	2.725	3.502
Bus680	Bus671	19.22	0.000	14.13	128.44	127.65	0.000	0.000
WTG5	Bas671	100.00	1.190	100.00	100.00	100.00	0.497	0.000
WTG6	Bus671	100.00	1.190	100.00	100.00	100.00	0.497	0.000
Lump3	Bus671	100.00	0.614	100.00	100.00	100.00	0.209	0.000
Lump7	Bus671	100.00	0.053	100.00	100.00	100.00	0.076	0.173
Bus633	Bus632	61.00	0.048	63.92	106.53	109.85	0.082	0.198
U2	Bus632	100.00	3.906	100.00	100.00	100.00	2.391	3.240
WTG7	Bus632	100.00	0.560	100.00	100.00	100.00	0.230	0.000
Lump9	Bus632	100.00	0.025	100.00	100.00	100.00	0.031	0.068
Bus634	Bus633	62.57	0.048	66.61	105.65	108.51	0.082	0.198
Lump1	Bus634	100.00	0.415	100.00	100.00	100.00	0.710	1.720
Bus671	Bus692	19.22	7.500	14.13	128.44	127.65	3.982	3.670

Table 3.69: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	7.060	0.00	127.89	132.21	3.856	3.856
Bus671	Bus680	34.91	7.060	33.22	117.83	121.53	3.856	3.856
Bus632	Bus671	69.32	3.501	72.46	103.83	108.26	2.050	2.608
WTG5	Bus671	100.00	0.923	100.00	100.00	100.00	0.377	0.000
WTG6	Bus671	100.00	0.923	100.00	100.00	100.00	0.377	0.000
Lump3	Bus671	100.00	0.476	100.00	100.00	100.00	0.159	0.000
Lump7	Bus671	100.00	0.041	100.00	100.00	100.00	0.057	0.129
Bus675	Bus692	37.51	1.249	35.42	118.53	119.95	0.858	1.136
Bus633	Bus632	69.45	0.037	72.95	103.65	107.95	0.061	0.148
U2	Bus632	100.00	3.029	100.00	100.00	100.00	1.798	2.413
WTG7	Bus632	100.00	0.434	100.00	100.00	100.00	0.174	0.000
Lump9	Bus632	100.00	0.019	100.00	100.00	100.00	0.023	0.050
WTG4	Bus675	100.00	0.891	100.00	100.00	100.00	0.361	0.000
Lump4	Bus675	100.00	0.360	100.00	100.00	100.00	0.497	1.136
Bus634	Bus633	70.67	0.037	74.92	103.14	106.90	0.061	0.148
Lump1	Bus634	100.00	0.322	100.00	100.00	100.00	0.530	1.281
Bus692	Bus671	34.91	1.249	33.22	117.83	121.53	0.858	1.136

Table 3.70: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	10.822	0.00	128.76	134.68	5.773	5.773
Bus675	Bus692	4.91	1.914	5.10	129.59	132.45	1.285	1.700
Bus632	Bus671	52.92	5.366	58.83	106.03	112.84	3.069	3.905
Bus680	Bus671	0.00	0.000	0.00	128.76	134.68	0.000	0.000
WTG5	Bns671	100.00	1.414	100.00	100.00	100.00	0.565	0.000
WTG6	Bus671	100.00	1.414	100.00	100.00	100.00	0.565	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.237	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.193
WTG4	Bus675	100.00	1.365	100.00	100.00	100.00	0.541	0.000
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.744	1.700
Bus633	Bus632	53.13	0.057	59.55	105.73	112.37	0.092	0.221
U2	Bus632	100.00	4.644	100.00	100.00	100.00	2.692	3.613
WTG7	Bus632	100.00	0.666	100.00	100.00	100.00	0.261	0.000
Lump9	Bus632	100.00	0.030	100.00	100.00	100.00	0.035	0.075
Bus634	Bus633	54.99	0.057	62.49	104.90	110.73	0.092	0.221
Lump1	Bus634	100.00	0.493	100.00	100.00	100.00	0.794	1.918
Bus671	Bus692	0.00	8.916	0.00	128.76	134.68	4.495	4.093

Table 3.71: Summary of Fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	4.024	-14.414	14.965	3.588	-9.183	9.859	13.080	3.597	13.565	-14.399	-0.452	14.406
Bus633	4.16	3.915	-8.993	9.808	2.777	-5.972	6.586	8.015	3.506	8.748	-8.998	-1.347	9.098
Bus634	0.48	9.709	-18.822	21.178	8.968	-17.500	19.664	16.401	8.479	18.463	12.271	16.540	20.595
Bus671	4.16	2.009	-10.634	10.822	1.575	-5.554	5.773	10.074	1.834	10.239	-10.521	-0.166	10.522
Bus675	4.16	2.512	-9.090	9.431	1.719	-5.015	5.301	8.554	2.338	8.868	-9.047	-0.780	9.080
Bus680	4.16	1.589	-6.879	7.060	1.104	-3.695	3.856	6.310	1.445	6.473	-6.649	-0.271	6.654
Bus692	4.16	2.009	-10.634	10.822	1.575	-5.554	5.773	10.074	1.834	10.239	-10.521	-0.166	10.522

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

3.3.9 Case 8: IEEE 13 Bus with 4*2 MW DG's Distributed at Different Locations in the Network

In this section IEEE 13 bus is simulated with a total DG penetration level of 8 MW decentralised DG's which are placed in the following configuration

- 1*2MW DG placed at bus 632
- 1*2MW DG placed at bus 671
- 1*2MW DG placed at bus 675
- 1*2MW DG placed at bus 680

Fig. 3.5 below illustrates the configuration of case 8.

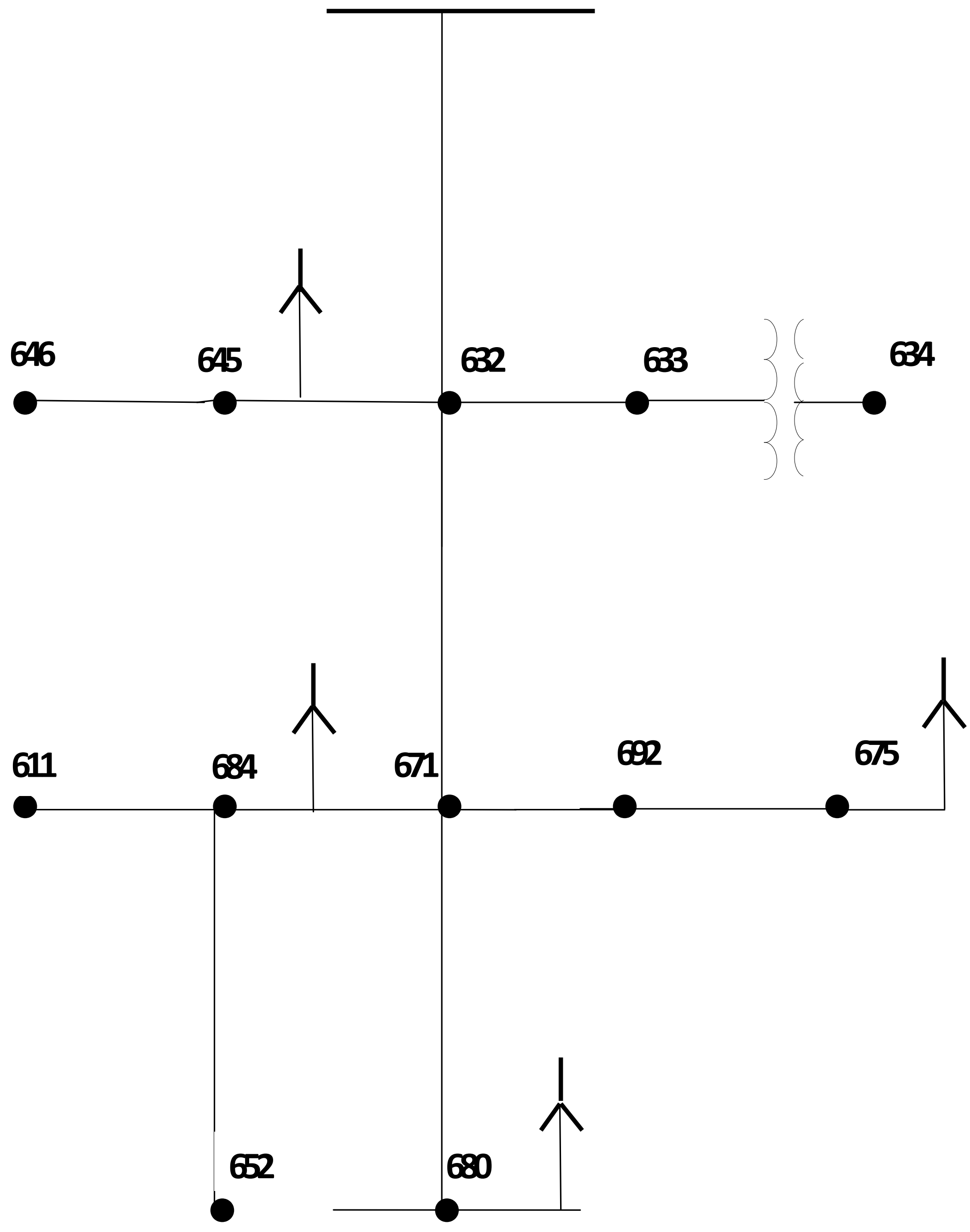

Fig.3.5: Configuration used in case 8

Table 3.72: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.04340	0.15493	0.16089	0.03847	0.14163	0.14676	0.18462	0.38503	0.42700
Bus633	4.160	0.09798	0.22487	0.24529	0.09313	0.21168	0.23126	0.27073	0.55637	0.61874
Bus634	0.480	0.00600	0.01163	0.01309	0.00594	0.01147	0.01292	0.00734	0.01453	0.01628
Bus671	4.160	0.04229	0.21966	0.22369	0.03303	0.18413	0.18707	0.26789	0.80107	0.84468
Bus675	4.160	0.06874	0.24701	0.25639	0.05698	0.20941	0.21702	0.31698	0.83323	0.89148
Bus680	4.160	0.06153	0.30070	0.30693	0.04943	0.25648	0.26120	0.39160	1.16385	1.22796
Bus692	4.160	0.04229	0.21966	0.22369	0.03303	0.18413	0.18707	0.26789	0.80107	0.84468

Table 3.73: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		**3-Phase Fault**		**Line-To-Ground Fault**				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	14.928	0.00	117.36	126.38	9.846	9.846
Bus67l	Bus632	35.13	3.562	29.52	114.82	120.71	2.063	1.261
Bus633	Bus632	0.46	0.121	1.67	116.47	125.30	0.213	0.489
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.805	7.977
WTG7	Bus632	100.00	1.414	100.00	100.00	100.00	0.736	0.000
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.082	0.167
Bus680	Bus671	39.42	0.867	31.57	115.44	121.32	0.415	0.000
WTG6	Bus671	100.00	0.926	100.00	100.00	100.00	0.451	0.000
Lump3	Bus671	100.00	0.478	100.00	100.00	100.00	0.190	0.000
Lump7	Bus671	100.00	0.042	100.00	100.00	100.00	0.059	0.129
Bus675	Bus692	37.92	1.253	32.15	115.61	119.23	0.949	1.132
Bus634	Bus633	4.42	0.121	8.68	113.91	121.68	0.213	0.489
WTG8	Bus68fl	100.00	0.867	100.00	100.00	100.00	0.415	0.000
WTG4	Bus675	100.00	0.894	100.00	100.00	100.00	0.432	0.000
Lump4	Bus675	100.00	0.361	100.00	100.00	100.00	0.518	1.132
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.847	4.234
Bus692	Bus671	35.13	1.253	29.52	114.82	120.71	0.949	1.132

Table 3.74: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus633	Total	0.00	9.792	0.00	119.39	121.37	6.580	6.580
Bus632	Bus633	36.47	9.670	34.68	111.23	115.21	6.365	6.095
Bus634	Bus633	3.99	0.121	7.05	116.71	117.97	0.215	0.485
Bus671	Bus632	58.99	2.326	54.09	109.76	111.76	1.367	0.821
U2	Bus632	100.00	6.441	100.00	100.00	100.00	4.490	5.196
WTG7	Bus632	100.00	0.924	100.00	100.00	100.00	0.490	0.000
Lump9	Bus632	100.00	0.041	100.00	100.00	100.00	0.054	0.109
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.860	4.207
Bus680	Bus671	61.78	0.566	55.45	110.15	112.10	0.276	0.000
WTG6	Bus671	100.00	0.605	100.00	100.00	100.00	0.300	0.000
Lump3	Bus671	100.00	0.312	100.00	100.00	100.00	0.126	0.000
Lump7	Bus671	100.00	0.027	100.00	100.00	100.00	0.039	0.084
Bus675	Bus692	60.94	0.818	55.87	110.30	110.75	0.626	0.737
WTG8	Bus680	100.00	0.566	100.00	100.00	100.00	0.276	o.ooo
WTG4	Bus675	100.00	0.584	100.00	100.00	100.00	0.287	0.000
Lutnp4	Bus675	100.00	0.236	100.00	100.00	100.00	0.339	0.737
Bus692	Bus671	58.99	0.818	54.09	109.76	111.76	0.626	0.737

Table 3.75: 3-phase & single line to ground fault currents when fault is at bus 643

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	21.170	0.00	104.10	103.50	19.658	19.658
Bus633	Bus634	76.12	20.078	67.99	105.40	105.23	17.935	16.504
Lump1	Bus634	100.00	1.09S	100.00	100.00	100.00	1.728	3.163
Bus632	Bus633	84.76	2.317	79.11	103.16	103.96	2.069	1.904
Bus671	Bus632	90.23	0.557	85.39	102.82	103.02	0.447	0.257
U2	Bus632	100.00	1.543	100.00	100.00	100.00	1.454	1.623
WTG7	Bus632	100.00	0.221	100.00	100.00	100.00	0.162	0.000
Lump9	Bus632	100.00	0.010	100.00	100.00	100.00	0.017	0.034
Bus680	Bus671	90.90	0.136	85.84	102.93	103.11	0.091	0.000
WTG6	Bus671	100.00	0.145	100.00	100.00	100.00	0.099	0.000
Lump3	Bus671	100.00	0.075	100.00	100.00	100.00	0.042	0.000
Lump7	Bus671	100.00	0.007	100.00	100.00	100.00	0.012	0.026
Bus675	Bus692	90.68	0.196	85.95	103.01	102.70	0.203	0.230
WTG8	Bus680	100.00	0.136	100.00	100.00	100.00	0.091	0.000
WTG4	Bus675	100.00	0.140	100.00	100.00	100.00	0.095	0.000
Lump4	Bus67S	100.00	0.057	100.00	100.00	100.00	0.108	0.230
Bus692	Bus671	90.23	0.196	85.39	102.82	103.02	0.203	0.230

Table 3.76: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	10.737	0.00	128.60	134.36	5.751	5.751
Bus632	Bus671	52.92	5.366	58.81	106.01	112.73	3.077	3.890
Bus680	Bus671	6.55	1.325	2.59	129.36	135.30	0.524	0.000
WTG6	Bus671	100.00	1.414	100.00	100.00	100.00	0.569	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.239	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.193
Bus675	Bus692	4.91	1.914	5.10	129.42	132.15	1.289	1.694
Bus633	Bus632	53.13	0.057	59.53	105.71	112.26	0.092	0.220
U2	Bus632	100.00	4.644	100.00	100.00	100.00	2.698	3.599
WTG7	Bus632	100.00	0.666	100.00	100.00	100.00	0.263	0.000
Lump9	Bus632	100.00	0.030	100.00	100.00	100.00	0.035	0.075
WTG8	Bus680	100.00	1.325	100.00	100.00	100.00	0.524	0.000
WTG4	Bus67S	100.00	1.365	100.00	100.00	100.00	0.545	0.000
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.743	1.694
Bus634	Bus633	54.99	0.057	62.47	104.88	110.63	0.092	0.220
Lump1	Bus634	100.00	0.493	100.00	100.00	100.00	0.793	1.911
Bus692	Bus67l	0.00	1.914	0.00	128.60	134.36	1.289	1.694

Table 3.77: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus675	Total	0.00	9.367	0.00	127.13	131.22	5.284	5.284
Bus692	Bus675	19.06	7.438	14.07	128.28	127.42	3.962	3.659
WTG4	Bus675	100.00	1.414	100.00	100.00	100.00	0.603	0.000
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.758	1.682
Bus632	Bus671	60.77	4.519	63.23	106.80	110.16	2.733	3.490
Bus680	Bus671	24.24	1.116	16.01	129.00	128.18	0.461	0.000
WTG6	Bus671	100.00	1.191	100.00	100.00	100.00	0.501	0.000
Lump3	Bus671	100.00	0.614	100.00	100.00	100.00	0.211	o.ooo
Lump7	Bus671	100.00	0.053	100.00	100.00	100.00	0.076	0.173
Bus633	Bus632	60.95	0.048	63.89	106.50	109.78	0.082	0.198
U2	Bus632	100.00	3.910	100.00	100.00	100.00	2.398	3.230
WTG7	Bus632	100.00	0.561	100.00	100.00	100.00	0.232	0.000
Lump9	Bus632	100.00	0.025	100.00	100.00	100.00	0.031	0.067
WTG8	Bus680	100.00	1.116	100.00	100.00	100.00	0.461	0.000
Bus634	Bus633	62.52	0.048	66.57	105.62	108.44	0.082	0.198
Lump1	Bus634	100.00	0.415	100.00	100.00	100.00	0.709	1.714
Bus671	Bus692	19.06	7.438	14.07	128.28	127.42	3.962	3.659

Table 3.78: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus680	Total	0.00	7.825	0.00	130.32	135.53	4.019	4.019
Bus671	Bus680	31.82	6.436	31.93	119.00	123.24	3.476	4.019
WTG8	Bus680	100.00	1.414	100.00	100.00	100.00	0.551	0.000
Bus632	Bus671	67.88	3.663	72.02	104.10	108.89	2.054	2.718
WTG6	Bus671	100.00	0.966	100.00	100.00	100.00	0,366	0.000
Lump3	Bus671	100.00	0.498	100.00	100.00	100.00	0.154	0.000
Lump7	Bus671	100.00	0.043	100.00	100.00	100.00	0.058	0.135
Bus675	Bus692	34.50	1.307	34.13	119.73	121.57	0.860	1.184
Bus633	Bus632	68.02	0.039	72.52	103.91	108.57	0.063	0.154
U2	Bus632	100.00	3.170	100.00	100.00	100.00	1.804	2.515
WTG7	Bus632	100.00	0.455	100.00	100.00	100.00	0.169	0.000
Lump9	Bus632	100.00	0.020	100.00	100.00	100.00	0.024	0.053
WTG4	Bus675	100.00	0.932	100.00	100.00	100.00	0.351	0.000
Lump4	Bus675	100.00	0.377	100.00	100.00	100.00	0.510	1.184
Bus634	Bus633	69.29	0.039	74.55	103.38	107.45	0.063	0.154
Lump1	Bus634	100.00	0.337	100.00	100.00	100.00	0.545	1.335
Bus692	Bus671	31.82	1.307	31.93	119.00	123.24	0.860	1.184

Table 3.79: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus692	Total	0.00	10.737	0.00	128.60	134.36	5.751	5.751
Bus675	Bus692	4.91	1.914	5.10	129.42	132.15	1.289	1.694
Bus632	Bus671	52.92	5.366	58.81	106.01	112.73	3.077	3.890
Bus680	Bus67l	6.55	1.325	2.59	129.36	13530	0.524	0.000
WTG6	Bus671	100.00	1.414	100.00	100.00	100.00	0.569	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.239	0.000
Lump?	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.193
WTG4	Bus675	100.00	1.365	100.00	100.00	100.00	0.545	o.ooo
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.743	1.694
Bus633	Bus632	53.13	0.057	59.53	105.71	112.26	0.092	0.220
U2	Bus632	100.00	4.644	100.00	100.00	100.00	2.698	3.599
WTG7	Bus632	100.00	0.666	100.00	100.00	100.00	0.263	0.000
Lump9	Bus632	100.00	0.030	100.00	100.00	100.00	0.035	0.075
WTG8	Bus680	100.00	1.325	100.00	100.00	100.00	0.524	0.000
Bus634	Bus633	54.99	0.057	62.47	104.88	110.63	0.092	0.220
Lump1	Bus634	100.00	0.493	100.00	100.00	100.00	0.793	1.911
Bus67l	Bus692	0.00	8.832	0.00	128.60	134.36	4.471	4.078

Table 3.80: Summary of Fault currents for all types of faults at each fault location

Bus		**3-Phase Fault**			**Line-to-Ground Fault**			**Line-to-Line Fault**			***Line-to-Line-to-Ground**		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	4.027	-14.375	14.928	3.585	-9.170	9.846	13.034	3.598	13.522	-14.356	-0.452	14.363
Bus633	4.16	3.911	-8.976	9.792	2.775	-5.966	6.580	7.997	3.501	8.730	-8.981	-1.342	9.080
Bus634	0.48	9.706	-18.814	21.170	8.966	-17.494	19.658	16.393	8.475	18.454	12.263	16.536	20.587
Bus671	4.16	2.030	-10.543	10.737	1.576	-5.531	5.751	9.956	1.857	10.128	-10.406	-0.186	10.408
Bus675	4.16	2.511	-9.025	9.367	1.716	-4.998	5.284	8.472	2.333	8.787	-8.967	-0.773	9.000
Bus680	4.16	1.569	-7.666	7.825	1.126	-3.858	4.019	7.181	1.430	7.322	-7.505	-0.266	7.509
Bus692	4.16	2.030	-10.543	10.737	1.576	-5.531	5.751	9.956	1.857	10.128	-10.406	-0.186	10.408

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer

3.3.10 Case 9: IEEE 13 Bus with 5*2 MW DG's Distributed at Different Locations in the Network.

In this section IEEE 13 bus is simulated with a total DG penetration level of 10 MW decentralised DG's which are placed in the following configuration

- 2*2MW DG placed at bus 632
- 2*2MW DG placed at bus 671
- 1*2MW DG placed at bus 675

The results of this case are tabulated below

Table 3.81: Positive, Negative and Zero Sequence Impedances as seen from each bus in the system

Bus		3-Phase Fault			Line-to-Ground Fault			Zero Sequence Imp. (ohm)		
ID	kV	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
Bus632	4.160	0.03658	0.14235	0.14697	0.03076	0.12608	0.12978	0.18462	0.38503	0.42700
Bus633	4.160	0.09125	0.21238	0.23116	0.08552	0.19625	0.21408	0.27073	0.55637	0.61874
Bus634	0.480	0.00592	0.01148	0.01292	0.00585	0.01128	0.01271	0.00734	0.01453	0.01628
Bus671	4.160	0.03929	0.21251	0.21611	0.03008	0.17629	0.17884	0.26789	0.80107	0.84468
Bus675	4.160	0.06642	0.24017	0.24919	0.05498	0.20207	0.20942	0.31698	0.83323	0.89148
Bus680	4.160	0.07463	0.32589	0.33432	0.06542	0.28967	0.29696	0.39160	1.16385	1.22796
Bus692	4.160	0.03929	0.21251	0.21611	0.03008	0.17629	0.17884	0.26789	0.80107	0.84468

Table 3.82: 3-phase & single line to ground fault currents when fault is at bus 632

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus632	Total	0.00	16.342	0.00	119.53	129.27	10.288	10.288
Bus671	Bus632	35.51	3.600	29.30	116.53	122.80	2.000	1.318
Bus633	Bus632	0.46	0.121	1.73	118.57	128.11	0.217	0.511
U2	Bus632	100.00	9.864	100.00	100.00	100.00	6.673	8.336
WTG7	Bus632	100.00	1.414	100.00	100.00	100.00	0.690	0.000
WTG9	Bus632	100.00	1.414	100.00	100.00	100.00	0.690	0.000
Lump9	Bus632	100.00	0.063	100.00	100.00	100.00	0.083	0.174
Bus680	Bus671	35.51	0.000	29.30	116.53	122.80	0.000	0.000
WTG5	Bus671	100.00	0.921	100.00	100.00	100.00	0.419	o.ooo
WTG6	Bus671	100.00	0.921	100.00	100.00	100.00	0.419	0.000
Lump3	Bus671	100.00	0.475	100.00	100.00	100.00	0.177	0.000
Lump7	Bus671	100.00	0.041	100.00	100.00	100.00	0.060	0.135
Bus675	Bus692	38.29	1.246	31.89	117.36	121.19	0.926	1.183
Bus634	Bus633	4.42	0.121	8.87	115.76	124.19	0.217	0.511
WTG4	Bus675	100.00	0.889	100.00	100.00	100.00	0.402	0.000
Lump4	Bus675	100.00	0.359	100.00	100.00	100.00	0.525	1.183
Lump1	Bus634	100.00	1.047	100.00	100.00	100.00	1.883	4.425
Bus692	Bus671	35.51	1.246	29.30	116.53	122.80	0.926	1.183

Table 3.83: 3-phase & single line to ground fault currents when fault is at bus 633

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus633	Total	0.00	10.390	0.00	120.91	123.00	6.774	6.774
Bus632	Bus633	38.72	10.269	35.72	112.40	116.52	6.557	6.275
Bus634	Bus633	3.99	0.121	7.14	118.06	119.42	0.217	0.500
Bus671	Bus632	60.72	2.279	54.68	110.70	112.68	1.305	0.845
U2	Bus632	100.00	6.244	100.00	100.00	100.00	4.336	5.349
WTG7	Bus632	100.00	0.895	100.00	100.00	100.00	0.452	0.000
WTG9	Bus632	100.00	0.895	100.00	100.00	100.00	0.452	0.000
Lump9	Bus632	100.00	0.040	100.00	100.00	100.00	0.053	0.112
Lump1	Bus634	100.00	1.052	100.00	100.00	100.00	1.884	4.331
Bus680	Bus671	60.72	0.000	54.68	110.70	112.68	0.000	0.000
WTG5	Bus671	100.00	0.583	100.00	100.00	100.00	0.275	0.000
WTG6	Bus671	100.00	0.583	100.00	100.00	100.00	0.275	0.000
Lump3	Bus671	100.00	0.301	100.00	100.00	100.00	0.116	0.000
Lump7	Bus671	100.00	0.026	100.00	100.00	100.00	0.039	0.086
Bus675	Bus692	62.61	0.789	56.41	111.27	111.59	0.601	0.759
WTG4	Bus675	100.00	0.563	100.00	100.00	100.00	0.263	0.000
Lump4	Bus675	100.00	0.227	100.00	100.00	100.00	0.338	0.759
Bus692	Bus671	60.72	0.789	54.68	110.70	112.68	0.601	0.759

Table 3.84: 3-phase & single line to ground fault currents when fault is at bus 634

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus634	Total	0.00	21.456	0.00	104.34	103.72	19.839	19.839
Bus633	Bus634	77.20	20.364	68.66	105.68	105.49	18.110	16.656
Lump1	Bus634	100.00	1.095	100.00	100.00	100.00	1.734	3.192
Bus632	Bus633	85.96	2.350	79.88	103.40	104.19	2.090	1.922
Bus671	Bus632	91.07	0.521	85.89	103.03	103.18	0.419	0.259
U2	Bus632	100.00	1.429	100.00	100.00	100.00	1.375	1.638
WTO7	Bus632	100.00	0.205	100.00	100.00	100.00	0.147	0.000
WTG9	Bus632	100.00	0.205	100.00	100.00	100.00	0.147	0.000
Lump9	Bus632	100.00	0.009	100.00	100.00	100.00	0.017	0.034
Bus680	Bus671	91.07	0.000	85.89	103.03	103.18	0.000	0.000
WTG5	Bus671	100.00	0.133	100.00	100.00	100.00	0.089	0.000
WTG6	Bus671	100.00	0.133	100.00	100.00	100.00	0.089	0.000
Lump3	Bus671	100.00	0.069	100.00	100.00	100.00	0.038	0.000
Lump7	Bus671	100.00	0.006	100.00	100.00	100.00	0.012	0.026
Bus675	Bus692	91.49	0.180	86.42	103.23	102.83	0.191	0.233
WTG4	Bus675	100.00	0.129	100.00	100.00	100.00	0.085	0.000
Lump4	Bus675	100.00	0.052	100.00	100.00	100.00	0.105	0.233
Bus692	Bus671	91.07	0.180	85.89	103.03	103.18	0.191	0.233

Table 3.85: 3-phase & single line to ground fault currents when fault is at bus 671

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	To Bus	%V	kA	% Voltage at From But			kA symm.rms	
ID	ID	From Bus	Symm.rms	Va	Vb	Vc	Ia	3I0
Bus671	Total	0.00	11.114	0.00	129.47	135.41	5.826	5.826
Bus632	Bus671	55.73	5.651	59.95	106.50	113.45	3.154	3.941
Bus680	Bus67l	0.00	0.000	0.00	129.47	135.41	0.000	0.000
WTG5	Bus671	100.00	1.414	100.00	100.00	100.00	0.554	0.000
WTG6	Bus671	100.00	1.414	100.00	100.00	100.00	0.554	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.233	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.195
Bus675	Bus692	4.91	1.914	5.09	130.30	133.14	1.276	1.716
Bus633	Bus632	55.93	0.053	60.67	106.20	112.96	0.091	0.223
U2	Bus632	100.00	4.367	100.00	100.00	100.00	2.570	3.646
WTG7	Bus632	100.00	0.626	100.00	100.00	100.00	0.237	0.000
WTG9	Bus632	100.00	0.626	100.00	100.00	100.00	0.237	0.000
Lump9	Bus632	100.00	0.028	100.00	100.00	100.00	0.034	0.076
WTG4	Bus675	100.00	1.365	100.00	100.00	100.00	0.531	0.000
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.746	1.716
Bus634	Bus633	57.68	0.053	63.58	105.33	111.28	0.091	0.223
Lump1	Bus634	100.00	0.464	100.00	100.00	100.00	0.786	1.935
Bus692	Bus671	0.00	1.914	0.00	129.47	135.41	1.276	1.716

Table 3.86: 3-phase & single line to ground fault currents when fault is at bus 675

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus675	Total	0.00	9.638	0.00	127.96	131.97	5.342	5.342
Bus692	Bus675	19.75	7.708	14.29	129.09	128.17	4.030	3.699
WTG4	Bus675	100.00	1.414	100.00	100.00	100.00	0.591	0.000
Lump4	Bus675	100.00	0.572	100.00	100.00	100.00	0.761	1.700
Bus632	Bus671	63.47	4.730	64.31	107.33	110.69	2.796	3.529
Bus680	Bus67I	19.75	0.000	14.29	129.09	128.17	0.000	0.000
WTG5	Bus671	100.00	1.184	100.00	100.00	100.00	0.487	0.000
WTG6	Bus671	100.00	1.184	100.00	100.00	100.00	0.487	o.ooo
Lump3	Bus671	100.00	0.611	100.00	100.00	100.00	0.205	0.000
Lump7	Bus671	100.00	0.053	100.00	100.00	100.00	0.076	0.175
Bus633	Bus632	63.64	0.045	64.97	107.01	110.29	0.081	0.200
U2	Bus632	100.00	3.656	100.00	100.00	100.00	2.280	3.265
WTG7	Bus632	100.00	0.524	100.00	100.00	100.00	0.209	0.000
WTG9	Bus632	100.00	0.524	100.00	100.00	100.00	0.209	0.000
Lump9	Bus632	100.00	0.024	100.00	100.00	100.00	0.030	0.068
Bus634	Bus633	65.10	0.045	67.62	106.10	108.91	0.081	0.200
Lump1	Bus634	100.00	0.388	100.00	100.00	100.00	0.702	1.733
Bus671	Bus692	19.75	7.708	14.29	129.09	128.17	4.030	3.699

Table 3.87: 3-phase & single line to ground fault currents when fault is at bus 680

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus680	Total	0.00	7.184	0.00	128.36	132.67	3.880	3.880
Bus671	Bus680	35.52	7.184	33.43	118.21	121.89	3.880	3.880
Bus632	Bus671	71.44	3.653	73.29	104.11	108.61	2.101	2.624
WTG5	Bus671	100.00	0.914	100.00	100.00	100.00	0.369	0.000
WTG6	Bus671	100.00	0.914	100.00	100.00	100.00	0.369	0.000
Lump3	Bus671	100.00	0.472	100.00	100.00	100.00	0.155	0.000
Lump7	Bus67I	100.00	0.041	100.00	100.00	100.00	0.057	0.130
Bus675	Bus692	38.10	1.237	35.61	118.91	120.30	0.850	1.143
Bus633	Bus632	71.57	0.035	73.78	103.92	108.30	0.060	0.149
U2	Bus632	100.00	2.823	100.00	100.00	100.00	1.711	2.428
WTG7	Bus632	100.00	0.405	100.00	100.00	100.00	0.158	o.ooo
WTG9	Bus632	100.00	0.405	100.00	100.00	100.00	0.158	0.000
Lump9	Bus632	100.00	0.018	100.00	100.00	100.00	0.023	0.051
WTG4	Bus675	100.00	0.883	100.00	100.00	100.00	0.353	0.000
Lump4	Bus675	100.00	0.357	100.00	100.00	100.00	0.497	1.143
Bus634	Bus633	72.71	0.035	75.73	103.40	107.22	0.060	0.149
Lump1	Bus634	100.00	0.300	100.00	100.00	100.00	0.523	1.289
Bus692	Bus671	35.52	1.237	33.43	118.21	121.89	0.850	1.143

Table 3.88: 3-phase & single line to ground fault currents when fault is at bus 692

Contribution		3-Phase Fault		Line-To-Ground Fault				
From Bus	**To Bus**	**%V**	**kA**	**% Voltage at From But**			**kA symm.rms**	
ID	**ID**	**From Bus**	**Symm.rms**	**Va**	**Vb**	**Vc**	**Ia**	**3I0**
Bus692	Total	0.00	11.114	0.00	129.47	135.41	5.826	5.826
Bus675	Bus692	4.91	1.914	5.09	130.30	133.14	1.276	1.716
Bus632	Bus671	55.73	5.651	59.95	106.50	113.45	3.154	3.941
Bus680	Bus671	0.00	0.000	0.00	129.47	135.41	0.000	0.000
WTGS	Bus671	100.00	1.414	100.00	100.00	100.00	0.554	0.000
WTG6	Bus67I	100.00	1.414	100.00	100.00	100.00	0.554	0.000
Lump3	Bus671	100.00	0.730	100.00	100.00	100.00	0.233	0.000
Lump7	Bus671	100.00	0.063	100.00	100.00	100.00	0.085	0.195
WTG4	Bus675	100.00	1.365	100.00	100.00	100.00	0.531	0.000
Lump4	Bus675	100.00	0.552	100.00	100.00	100.00	0.746	1.716
Bus633	Bus632	55.93	0.053	60.67	106.20	112.96	0.091	0.223
U2	Bus632	100.00	4.367	100.00	100.00	100.00	2.570	3.646
WTG7	Bus632	100.00	0.626	100.00	100.00	100.00	0.237	0.000
WTG9	Bus632	100.00	0.626	100.00	100.00	100.00	0.237	0.000
Lump9	Bus632	100.00	0.028	100.00	100.00	100.00	0.034	0.076
Bus634	Bus633	57.68	0.053	63.58	105.33	111.28	0.091	0.223
Lump1	Bus634	100.00	0.464	100.00	100.00	100.00	0.786	1.935
Bus671	Bus692	0.00	9.207	0.00	129.47	135.41	4.557	4.131

Table 3.89: Summary of Fault currents for all types of faults at each fault location

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	**kV**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**	**Real**	**Imag.**	**Mag.**
Bus632	4.16	4.067	-15.828	16.342	3.701	-9.599	10.288	14.580	3.657	15.032	-15.874	-0.507	15.882
Bus633	4.16	4.102	-9.546	10.390	2.850	-6.145	6.774	8.575	3.710	9.343	-9.548	-1.540	9.671
Bus634	0.48	9.834	-19.069	21.456	9.049	-17.654	19.839	16.638	8.605	18.732	12.493	16.684	20.843
Bus671	4.16	2.021	-10.928	11.114	1.589	-5.605	5.826	10.369	1.850	10.533	-10.814	-0.180	10.816
Bus675	4.16	2.569	-9.290	9.638	1.737	-5.052	5.342	8.747	2.401	9.071	-9.239	-0.839	9.277
Bus680	4.16	1.604	-7.003	7.184	1.111	-3.717	3.880	6.426	1.462	6.590	-6.764	-0.286	6.770
Bus692	4.16	2.021	-10.928	11.114	1.589	-5.605	5.826	10.369	1.850	10.533	-10.814	-0.180	10.816

In the case of **line-to-line-to-ground** fault there is a contribution of zero sequence fault current (3I0) from a grounded Delta- Y transformer.

This part listed all the simulation results for all nine cases for each fault location. Those results will be used and referred to in the following part to study the impacts of DG penetration on the networks and on protection equipment.

3.4 Discussion

In this section, the results of the simulation will be discussed to verify the impact of DG on fault currents, short circuit levels and effect on protection equipment, Results show the values of four types of faults but the discussion will concern only single line to ground fault as it is the most common and occurring fault. Table 3.90 below lists the fault currents in each case when the fault is at different buses, those values were used to make comparison charts to compare the fault current at each case with the standard case which is case 1.

Table 3.90: Fault currents for all cases with different fault locations

Location of Fault	Case1	Case 2	Case3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
632	8.444	10.451	9.085	9.554	9.465	9.380	9.859	9.846	10.288
633	5.925	6.846	6.567	6.448	6.405	6.368	6.586	6.580	6.774
634	18.991	19.905	35.309	19.530	19.487	19.451	19.664	19.658	19.839
671	4.514	4.904	4.651	5.980	5.849	5.720	5.773	5.751	5.826
675	4.163	4.488	4.276	5.354	5.666	5.145	5.301	5.284	5.342
680	3.250	3.448	3.321	3.947	3.889	4.408	3.856	4.019	3.880
692	4.514	4.904	4.651	5.980	5.849	5.720	5.773	5.751	5.826

For case 1, the simulation is made without the presence of any DG in the system to obtain the standard behaviour of the system. Fig. 3.6, below presents case 1,

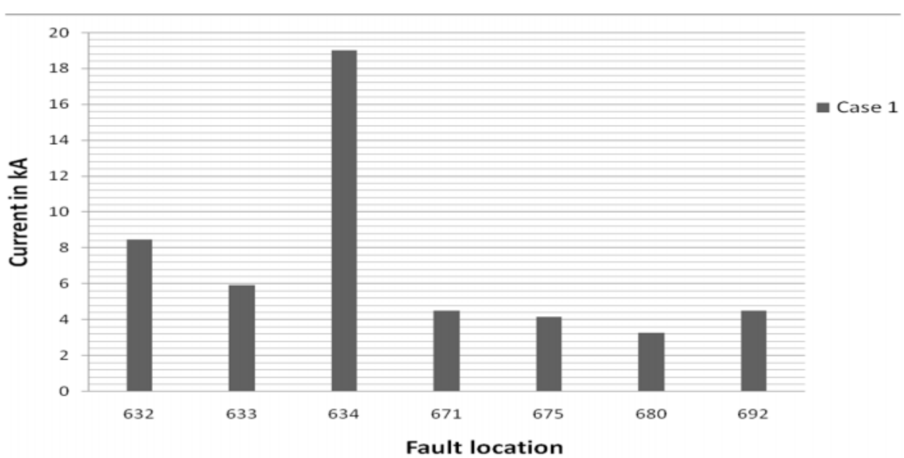

Fig.3.6: Fault current at different fault locations for case 1.

The above chart shows the values of short circuit currents at the studied buses of the network and is considered the base and set values of all protection equipment, those values will be compared with the values recorded from all the other cases. It is clear from Fig. 3.6 that the highest short circuit level reported is with the fault location at bus 634, and this is due to the presence of that bus at the low voltage side of a transformer, and the fault voltage is 480 V, the rest of fault locations have a fault voltage of 4.16 kV.

For case 2, one large centralised 8 MW DG is placed at bus 632 and a comparison chart is made between case 1 & case 2 in Fig. 3.7 to investigate the impact of the added DG.

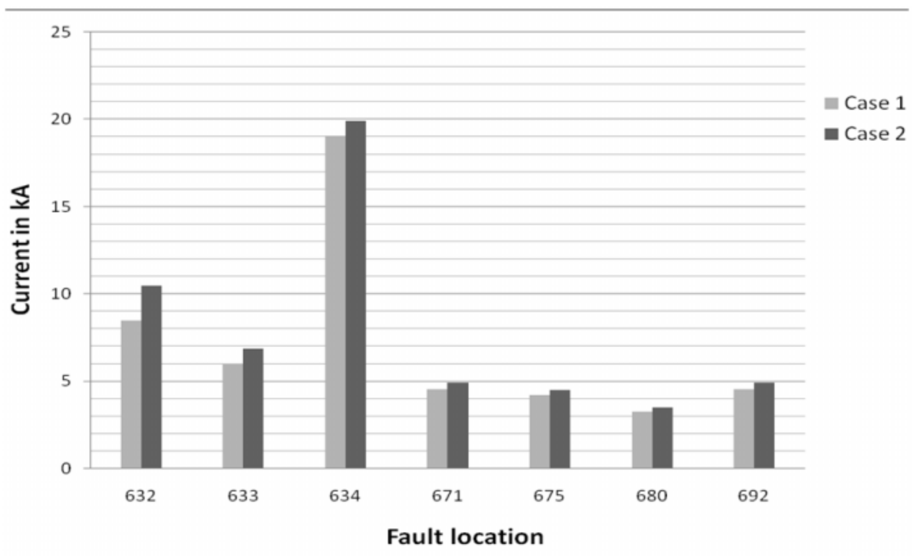

Fig.3.7: Comparison between case 1 and case 2

It is clear from the chart that placing the DG at bus 632 will increase the short circuit level of the network. The maximum increase is at bus 632 and this seems to be quite reasonable as the DG is located at this bus, thus the distance between the DG and the fault is too small and the current is not damped at all, this close distance lead to an increase in the percentage of DG contribution to the fault, consequently increasing the value of short circuit level. Increase in short circuit levels at other buses is less than that at bus 632 due to the close distance of the fault location from both utility and the DG.

In case 3, one large centralised DG is placed at bus 634. Fig. 3.8, shows a comparison between case 3 and case 1.

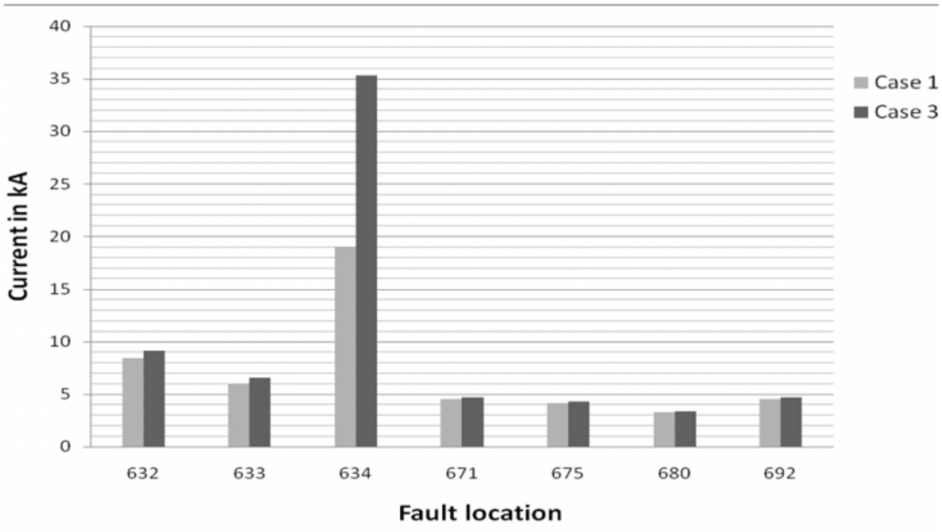

Fig.3.8: Comparison between case 1 and case 3

Referring to the chart, it is clear that placing the DG at bus 634 caused a slight increase of the short circuit level of the network, but when the fault location is at bus 634, the percentage contribution of the DG to the fault is **49.7%**, and this caused a total increase in the fault current by **90%**. DG contribution in this case is high due to the presence of both the DG and the fault location in a close distance as both are at the same side of the transformer, besides the operation of the DG is at a low voltage thus the short circuit current contributed by the DG is so high. On the other hand the value of the short current flowing to bus 634 from the entire network is quite low when compared to the fault current, it is **1.821 kA** and the fault current is **35.309 kA**, but when transformed by the transformer it became a considerable value of **15.784 kA**. The substation has a fault percentage contribution of **39%**.

In case 4, one large centralised DG is placed at bus 671, Fig. 3.9 below shows a comparison between cases 1 and 4.

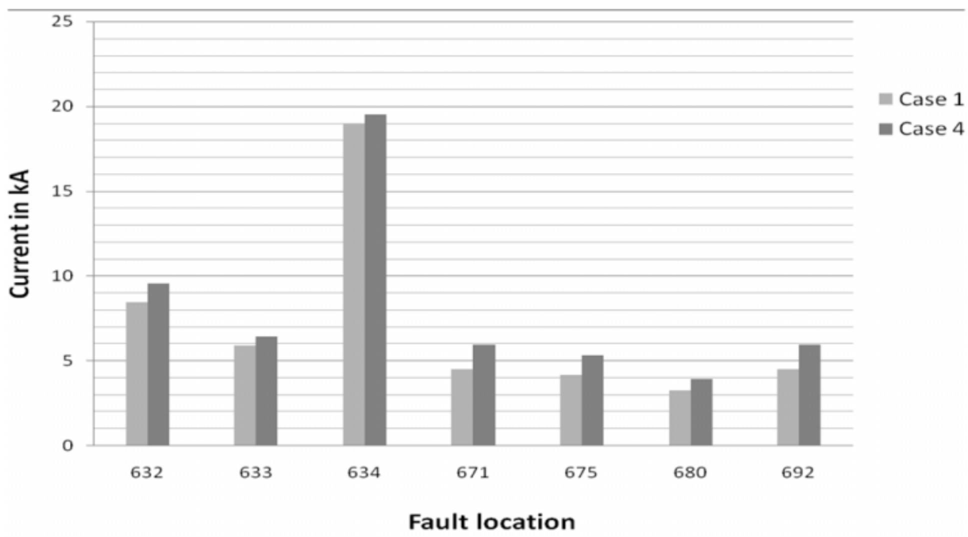

Fig.3.9: Comparison between case 4 and case 1

Fig. 3.9 shows that the presence of a DG at bus 671 increased the short circuit currents of the network. The largest increase reported is when the fault location is at bus 671, this percentage increase is **33%**. This escalation in the fault current is a result of the small distance between the DG and the fault location. As the distance between the fault location and the DG increases, the contribution of the DG to the fault decreases, consequently the rise in fault current will decrease as there will always be an increase in the fault current when a DG is added to the system. It can be generalized that as the distance of the fault location from any generating source increases the contribution of the generating source to the fault will decrease.

In case 5, one large centralised DG is placed at bus 675. Fig. 3.10 below illustrates a comparison between cases 5 and 1.

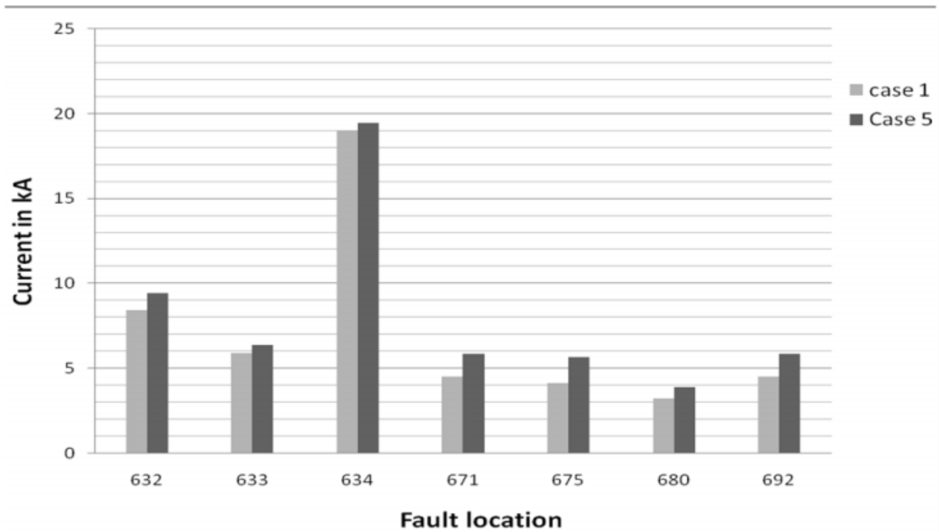

Fig.3.10: Comparison between case 5 and case 1

Fig. 3.10 clearly states that, placing a DG at bus 675 causes an increase of the short circuit level at all buses with a maximum increase at bus 675 where the DG is located and this is common in all the previous cases, the maximum increase in fault current is at the bus at which the DG is located. The percentage increase in fault current at bus 675 is reported to be **33%**.

Case 6 illustrates the condition of placing one large centralised 8 MW DG at bus 680. Placing a DG at this bus has a great effect on the system. Fig. 3.11 below presents a comparison between case 6 and case 1

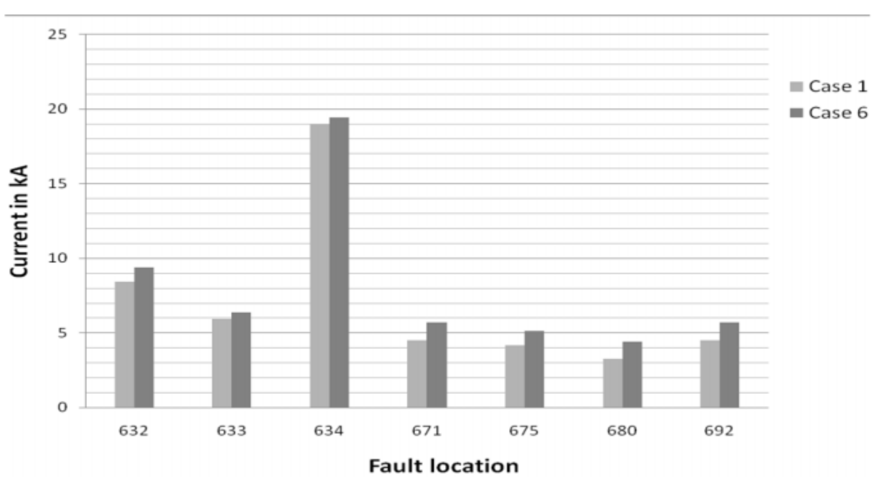

Fig.3.11: Comparison between case 6 and case 1

When studying Fig. 3.11, it is realised that placing a DG at bus 680 increased the short circuit level of the network and it caused a short circuit current to flow in the branch between buses 671and 680 that is eliminated in all cases except when the fault location is at bus 680. Placing the DG at bus 680 might cause a lot of problems to the existing protection scheme as the percentage fault current increase reported is **35.6%**, this value also represents the percentage increase in the short circuit current flowing through the branch between buses 671 and 680. The reported increase could be sufficient to cause a "**reduction of reach**" to the protection equipment responsible about protecting this part of the network.

Case 7 is the first case at which the large centralised DG is replaced by smaller DGs with the same total generating capacity. In this case, four distributed 2 MW DGs are placed at buses 632, 671 and 675. Fig. 3.12 below shows a comparison between cases 7 and 1.

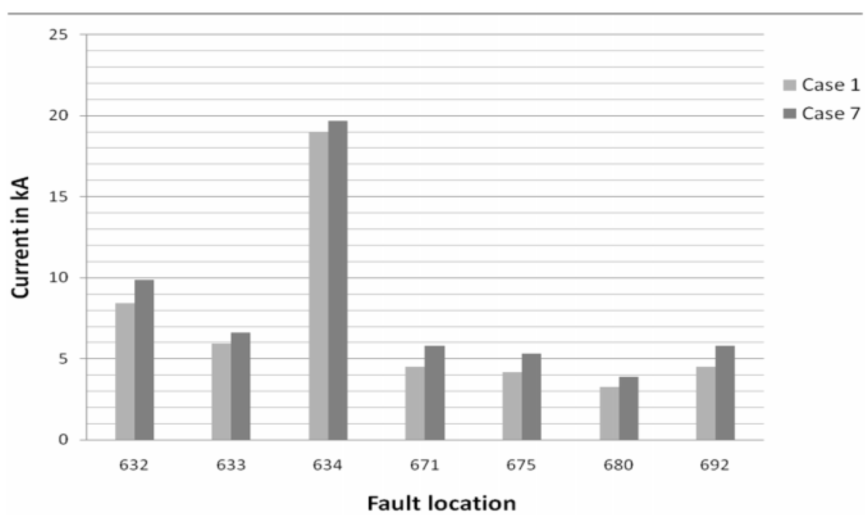

Fig.3.12: Comparison between case 7 and case 1

Fig. 3.12 can be used to study the difference between the impact of one large centralised DG and this case. It is clear from the results of this case that the penetration of those four small DGs into the network caused an increase in the fault level of the network, the amount of increase is a function of the configuration but the difference between the effect of centralised and decentralised cases can be sensed from the percentage contribution to faults of both the substation and the DG. Decentralised DGs showed that the percentage of overall DG contribution to fault is increased and the fault currents are also increased for all fault locations, while the percentage contribution of the substation is decreased. Centralised DG with the same total generating capacity located in all locations showed an increase of the fault currents along with the increase in the percentage of DG contribution to faults that is configuration dependent. It is observed that decentralising the DG increases the percentage of DG contribution to faults and decreases the percentage of utility contribution to faults. The maximum increase in the fault current is reported when the fault location is at bus 632; this is due to the presence of one of the DGs at this bus besides the close distance of this bus from the substation.

For case 8, four distributed 2 MW DG are located at buses 632, 671, 675 and 680. Fig. 3.11 illustrates a comparison between case 8 and case 1.

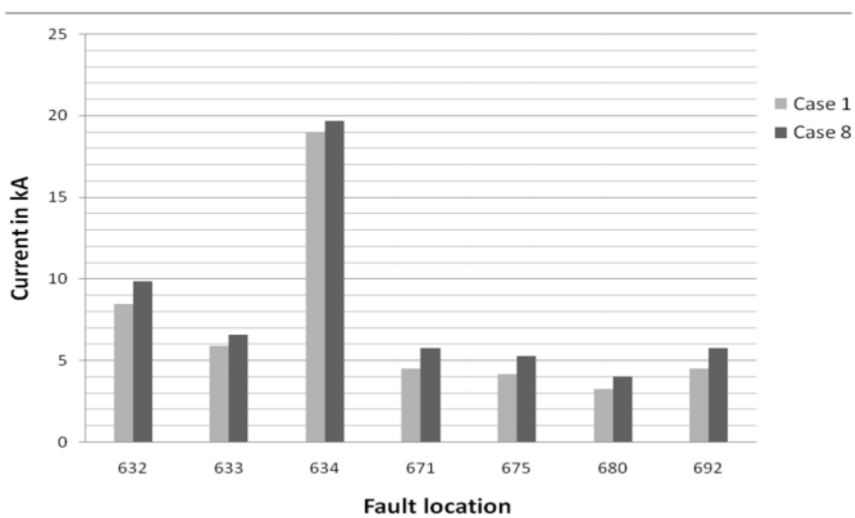

Fig.3.13: Comparison between case 1 and case 8

This case is similar to the previous case with close results. The above figure showed an increase in the fault level of the network with a maximum increase at bus 632. When comparing this case with the previous case, it is observed that the configuration of case 8 has a higher substation contribution to faults for fault locations other than at bus 680. When the fault is at this bus, the value of the fault current is higher than that of case 7. The difference between both cases is too small at all fault locations except for the fault location at buses 633 and 680.

For case 9, five distributed 2 MW DG located at buses 632, 671 and 675. Fig. 3.14 illustrates a comparison between case 1 and case 9

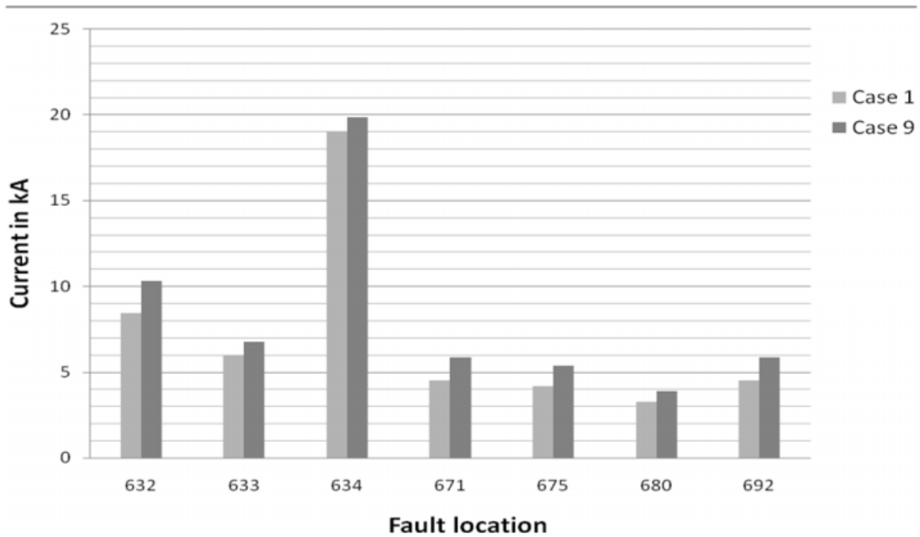

Fig.3.14: Comparison between case 1 and case 9

This case is a unique case at which the total generating capacity of all DGs is 10 MW. It is obvious that the increase in fault is higher when compared with all cases as the level of DG penetration into the network is higher. It is clear from the above figure that the maximum increase in fault level is when the fault is at bus 632, and this is due to the close distance between bus 632 and the substation in addition to the presence of two DGs at this bus. The configuration in this case caused a decrease in the percentage contribution of the substation to faults at all fault locations, but on the other hand, it caused an increase of the percentage DG contribution to faults.

To study the effect of changing the DG location on the network, cases 2 to 6 are considered, while cases 7 to 9 are considered to study the difference between centralising and decentralising the DG. Fig. 3.15 below illustrates a comparison between fault currents at each fault location for all cases.

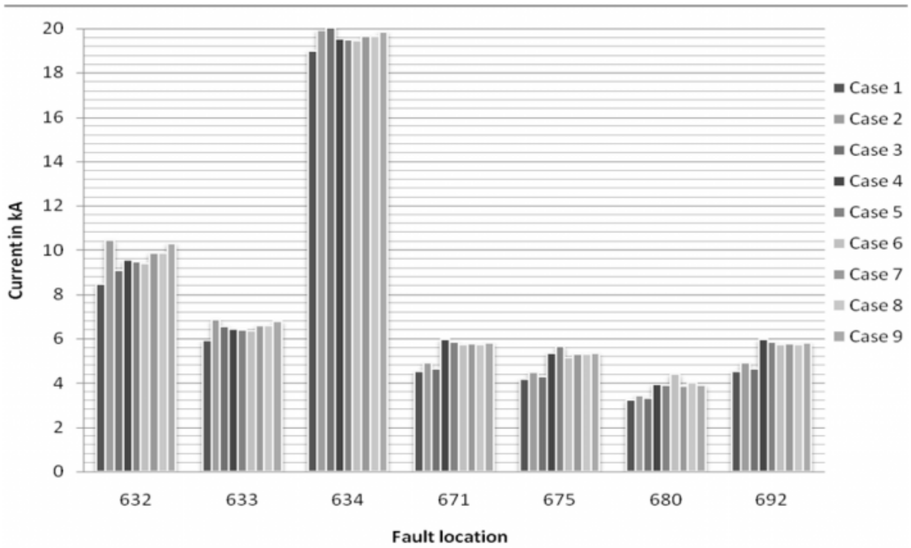

Fig.3.15: Comparison between fault currents for all cases

Referring to Fig. 3.15, when the fault location is at bus 632; case 2 has the maximum fault current due to the close distance of the fault location from the utility substation and the presence of a DG at the faulted bus. Placing the DG at bus 634 showed the least impact on the fault current due to the presence of a transformer between bus 633 and bus 634, the DG is operating at the low voltage side thus the high short circuit currents produced by the DG are transformed to the high tension side of the transformer to lower values. A portion of the transformed current represents the contribution of the DG to the fault; consequently the fault current will not increase as the rest of the cases, the percentage DG contribution to the fault is 10% from the total fault current while the substation contribution is reported to be 77.3%. It is clear from the above figure that centralising the DG showed less impact on the fault current at bus 632 as cases 7 to 9 caused the fault current to increase. Configurations of DGs used in cases 7, 8 and 9 caused a decrease in the substation contribution to the fault and caused the DGs to play a higher role during the fault as a result of the presence of a DG at bus 632. The presence of any DG at a faulted bus has a great impact on this bus fault level.

The situation at which bus 633 is the faulted bus showed the same response of the network to the different configurations of the DG but with lower fault currents when compared with bus 632 as the faulted bus. Fault currents at bus 633 are less than that at bus 632 due to the increase in the distance between the substation and the fault.

Bus 634 is a unique bus in the system; it is the only bus that is operating at 480V while the rest of the network buses are operating at 4.16 kV. The presence of a transformer caused the effect of any DG in the network to be reduced when the fault is at bus 634, and the effect of the DG when placed at bus 634 to be reduced at all fault locations other than bus 634 itself. The highest fault currents observed at all fault locations is at bus 634; this is because of the low operating voltage that causes the fault currents to be high. The most severe fault current is the current observed in case 3 at which the DG was placed at bus 634. The DG has a contribution to the fault of 49.7% while the substation has a percentage contribution of 39%.

Buses 671 and 692 are considered as the same bus as the difference between both is a switch so the results at both buses are identical. Results are showing less fault levels than the previous fault locations, and this is due to the increase in distance away from the substation. At bus 671, the highest short circuit current observed is the current of case 4, at which one DG was placed at bus 671, followed by case 5 at which the DG was placed at bus 675. Cases 7 and 8 had less fault currents which showed that decentralising the DG causes the fault current to be slightly less than cases 4 and 5 but slightly higher than case 6. The DG configuration used in case 7 resulted in 46.6% substation contribution and 33.5% DG contribution to the fault when the fault is at bus 671 or at bus 692, while configuration used in case 8 resulted in 47% substation contribution and 33% DG contribution.

For the fault location at bus 675, the highest fault current observed is case 5 at which the DG is located at the same bus. This fault location showed that using several small capacity DG’s is better than using one large centralised DG. The increases in fault currents at this bus for cases 7, 8 and 9 respectively are 27.3%, 26.9% and 28.3%, which shows that it is less than cases 4 and 5, but higher than case 6 due the absence of any DG in a close distance, similarly with cases 2 and 3 the location of the DG is a large distance from the fault besides the far distance of the fault away from the substation, so the fault current reported in both cases shows a low increase of 7.8% and 2.7% respectively. At this fault location, case 9 has the least substation contribution to the fault due to the use of several DGs, which caused the overall impedance of the network to be higher, this causes the current contributed from the substation to the fault to be reduced.

Bus 680 has the lowest fault currents in the whole system and usually in any fault location in the system other than bus 680 there will be no current flowing from or to this bus, if there is no DG located at this bus. Results at 680 show that as the distance of the fault location increases away from the substation the less the fault level is at that bus. When comparing cases 7 and 8, it is observed that case 7 has a lower fault level due to the presence of a DG at bus 680 in case 8. Case 9 showed that the effect of decentralising the DG has less impact on a faulted bus that does not have a DG interconnected to it, although the generating capacity of case 9 is higher than that of case 8, but the value of the short circuit current observed in case 9is less than that of case 8 and this is due to the DG configuration used.

It is clear from results that the system lost its radiality in power and current flow, thus protection devices are severely affected by the presence of DG in the network. The DG might cause a failure in the desired existing protection scheme in some cases due to the impact of DG penetration on the fault levels of the network which is a factor of DG size, location (configuration) and type of DG used. This leads to various mis protection scenarios and undesired consequences such as the loss of coordination between protective devices, which is quite clear in case 5 when the fault is at bus 692 and might lead to an unintentional islanding if a fuse is blown away at bus 692 leaving the DG energising part of the network.

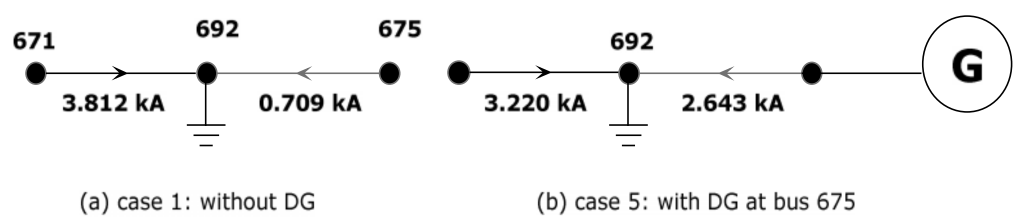

Fig.3.16: illustrating the possibility of fuse blowing

It is clear from Fig. 3.16 that after the penetration of the DG, the fault current flowing through bus 671 to bus 692 is decreased by 16.5% from the normal case which is case 1. As a result of this decrease, protection devices will not sense a fault, thus no tripping will occur to isolate the fault at bus 671 as there is no fault conditions from the protective devices' point of view. On the other hand, the fault current flowing from 675 to 692 is 3.72 times the designed current which is considered a large increase that will have a great effect on protective devices. If the protection scheme is based on the coordination between fuse, recloser and breaker to perform fuse saving technique, it will fail due to the several multiples of the fault current that will cause the fuse to operate first due to the inverse time over current characteristics, the fuse operates before the fast strike of the recloser. If the fuse blows out, then the DG will be left energising the loads connected to bus 675 performing a power island, but the DG is capable of supplying several multiples of these loads which might lead to severe trouble.

Running the simulation on IEEE 13 bus came out with numerical values presenting the values of currents flowing in the network. Table 3.91 lists the values of fault currents' flowing in the branch from bus 650 to bus 632 and Fig. 3.17 is a plot of the fault currents flowing in the same branch for all the studied cases at all studied fault locations. Bus 632 is the link between the utility and the entire network thus the current flowing from bus 650 to bus 632 is the fault current flowing from the utility to the network.

Table 3. 91: Fault currents in branch from bus 650 to bus 632

	632		**633**		**634**		**671**		**675**		**680**		**692**	
	I_f (kA)	**% D**	**I_f (kA)**	**% D**	**I_f (kA)**	**% D**	**I_f (kA)**	**% D**	**I_f (kA)**	**% D**	**I_f (kA)**	**% D**	**I_f (kA)**	**% D**
Case 1	7.225	0.00	5.014	0.00	1.749	0.00	3.275	0.00	2.975	0.00	2.358	0.00	3.275	0.00
Case 2	6.632	8.21	4.287	**14.50**	1.349	**22.87**	2.602	20.55	2.345	21.18	1.830	22.39	2.602	20.55
Case 3	7.021	2.82	4.797	4.33	1.580	9.66	3.305	-0.92	2.747	7.66	2.167	8.10	3.305	-0.92
Case 4	6.880	4.78	4.592	8.42	1.509	13.72	2.740	16.34	2.414	18.86	1.809	23.28	2.740	16.34
Case 5	6.910	4.36	4.619	7.88	1.525	12.81	2.782	15.05	2.479	16.67	1.850	21.54	2.782	15.05
Case 6	6.939	3.96	4.654	7.18	1.543	11.78	2.833	13.50	2.507	15.73	1.865	20.91	2.833	13.50
Case 7	6.801	5.87	4.485	10.55	1.452	16.98	2.692	17.80	2.391	19.63	1.798	23.75	2.692	17.80
Case 8	6.805	5.81	4.490	10.45	1.454	16.87	2.698	17.62	2.398	19.39	1.804	23.49	2.698	17.62
Case 9	6.673	**7.64**	4.336	13.52	1.375	21.38	2.570	**21.53**	2.228	**25.11**	1.711	**27.44**	2.570	**21.53**

%D is the percentage decrease in the short circuit current flowing through that branch

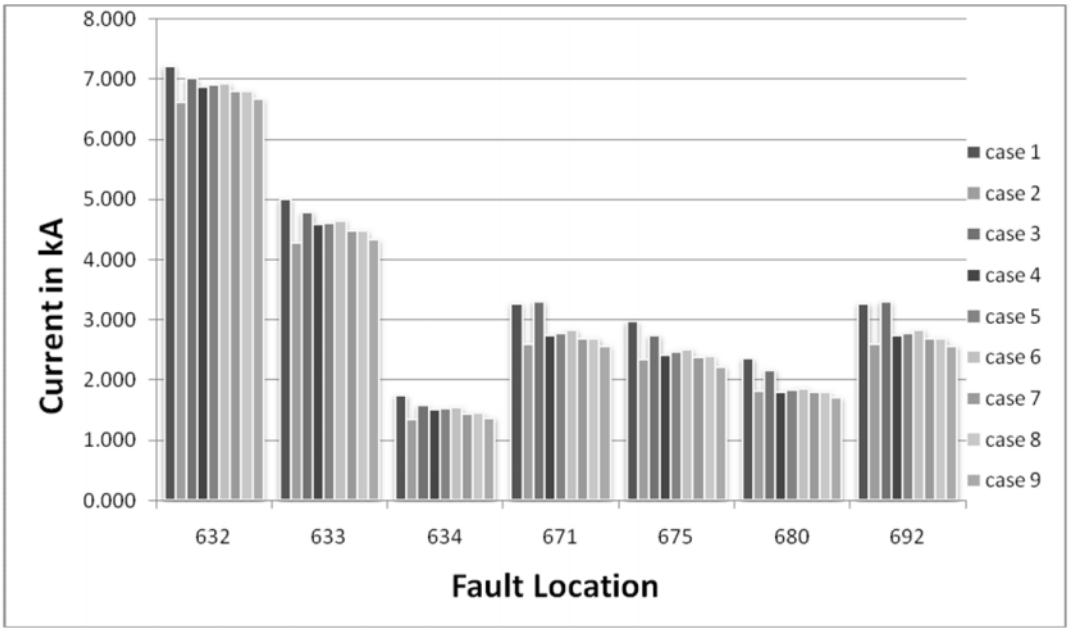

Fig.3.17: Fault current in branch from bus 650 to bus 632.

Bus 650 to bus 632 has a special behavior as the only source of current in this branch is the utility so the current is always flowing in one direction cause all the fault locations on the main feeder. Fig. 3.17 shows a comparison between all cases while the fault is at different locations. For each fault location nine current values are plotted, those nine values are called set of results at the certain fault location. i.e. set 1 is the group of fault current values of 9 cases when fault is at bus 632. Set 2 is the group of fault currents when the fault is at bus 633 and so on. Current flowing in this bus is the fault current contributed by the substation to the fault. It is clear that cases 7, 8 and 9 decrease the substation contribution. This shows that decentralising the DG has a positive impact on the substation.

Set 1 has the highest fault current flowing in branch from bus 650 to bus 632 and the reason for this is that bus 632 is the closest bus to the utility, so the network's thevenin equivalent impedance is low; consequently the fault current values are high. As the distance of fault location increases, the value of fault current decreases. This can be seen from the comparison figure by considering set 2, the distance increased away from the substation resulting in a decrease of the fault level. Set 3 is out of spot as it is the only bus in the network with a voltage of 480 V and it is the only bus that has a transformer connected to it, bus 634 is operating at the low tension side of the transformer. The highest fault current in the entire network is at bus 634 but when transformed to the high tension side the value of fault current contributed from the DG to the fault becomes quite low compared to that of naturally high voltage faults, this heads to ignoring set 3 in the comparison.

Bus 680 is the furthest bus from bus 650 thus set 6 has the lowest fault current values due to the high thevenin equivalent impedance of the network when the fault is at that bus.

Sets 4 and 7 are identical with all fault currents having the same value as the difference between bus 671 and 692 is a switch which has no effect on the impedance between both buses thus the current flowing from 692 to 671 is neither damped nor increased. The main factor affecting the fault current groups is the distance of the fault from bus 650 which represents the utility. All sets seem to have the same behavior meaning that the effect of DG configuration (case) is the same at all fault locations; case 2 is the least fault current of the set while case 1 is the highest, this indicates the decrease in utility contribution to fault currents. This shows that presence of DG in the network decreases the contribution of utility to faults while the fault current itself is increased. (i.e. presence of DG in network decreases the percentage utility contribution to faults). Cases 2, 3, 4 and 5 are simulated using one centralised DG while cases 7, 8, and 9 are simulated using a decentralised DG configuration, results show that centralised DG has less effect on decreasing the percentage utility contribution while decentralised DG with a total capacity equal to the centralised DG capacity as in cases 7 and 8, causes a decrease in the % utility contribution, except for case 2 which the DG is at the fault location, this case increases the impedance of the network causing the percentage DG contribution to increase, while case 9 shows that as the de-centralised DG capacity increase, the percentage utility contribution decreases while the value of fault current is increased. Cases 2 and 9 are the two cases that will probably have an effect on the protection equipment as the percentage decrease of the current flowing through this branch is high which might decrease the sensitivity of the protection equipment causing fault conditions to not be discriminated an d no tripping will occur

Studying the branch from bus 632 to bus 671 is performed using the outcome of the software and results are tabulated below in Table 3.92.

Table 3. 92: Fault currents for branch from bus 632 to 671

	632		633		634		671		675		680		692	
	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$	$I_{sh.}$	% $I_{sh.}$
Case 1	0.96	100.00	0.67	100.00	0.23	100.00	3.40	100.00	3.08	100.00	2.44	100.00	3.40	100.00
Case 2	0.91	94.38	0.59	87.84	0.18	78.88	3.80	111.90	3.43	111.09	2.67	109.29	3.80	111.90
Case 3	0.94	98.13	0.65	97.00	0.23	97.41	3.54	104.24	3.20	103.92	2.53	103.36	3.54	104.24
Case 4	2.41	250.88	1.61	242.34	0.54	231.47	2.87	84.48	2.53	81.97	1.89	77.45	2.87	84.48
Case 5	2.28	237.04	1.54	230.48	0.51	221.12	2.91	85.71	2.60	84.20	1.94	79.17	2.91	85.71
Case 6	2.18	226.95	1.47	220.57	0.49	212.07	2.97	87.45	2.62	84.95	1.96	80.03	2.96	87.16
Case 7	2.08	216.65	1.38	207.06	0.45	194.40	3.07	90.40	2.73	88.39	2.05	83.88	3.07	90.40
Case 8	2.06	214.67	1.37	205.26	0.45	192.67	3.08	90.63	2.73	88.65	2.05	84.04	3.08	90.63
Case 9	2.00	208.12	1.31	195.95	0.42	180.60	3.15	92.90	2.80	90.69	2.10	85.97	3.15	92.90

The above table shows the values of fault current (**I_{sh}**) flowing in the branch from bus 632 to bus 671 at all fault locations and with different cases, in addition to the percentage of fault current (**%I_{sh}**) from the set value which is the current flowing in this branch without the presence of any DG (case 1). Results in the table were used to plot the comparison chart shown in Fig. 3.18 below.

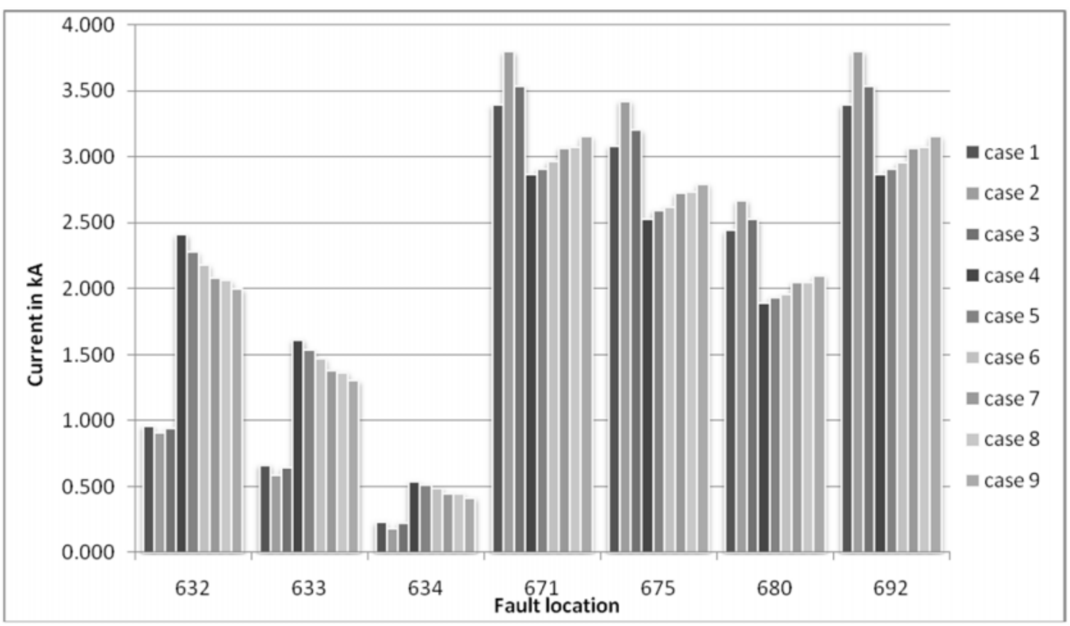

Fig.3.18: Short circuit current flowing in branch from bus 632 to bus 671 in all cases with different fault locations

This branch is considered as a main feeder branch; at which current passes through to be delivered to several laterals to reach the loads. It is clear from Fig. 3.15 that there is a great difference between the current levels flowing through this branch which is considered as a hazard to the protection equipments when using some of the studied DG configurations. Designing a protection scheme for this branch will be so difficult in some cases due to the huge difference in levels of the current flowing through it. According to Table 3.92, case 2 seems to be the best DG configuration to be used for maintaining the existing protection scheme for this branch and it may not affect the coordination of the existing protection devices as the variations reported in this case have a maximum of 11%.

It is clear that the location of the fault is the main factor affecting the fault level besides the DG configuration; consider set 1 for study at which the fault is at bus 632. In set 1, the values of the short circuit current flowing through this branch in cases 2 and 3 are 5.62% and 1.87% less than that of case 1, which will not cause a considerable effect. The current flowing in these two cases does not contain the short circuit current contributed from any DG to the fault. Fig. 3.19 below illustrates the short circuit currents flowing through this branch during a fault at bus 632.

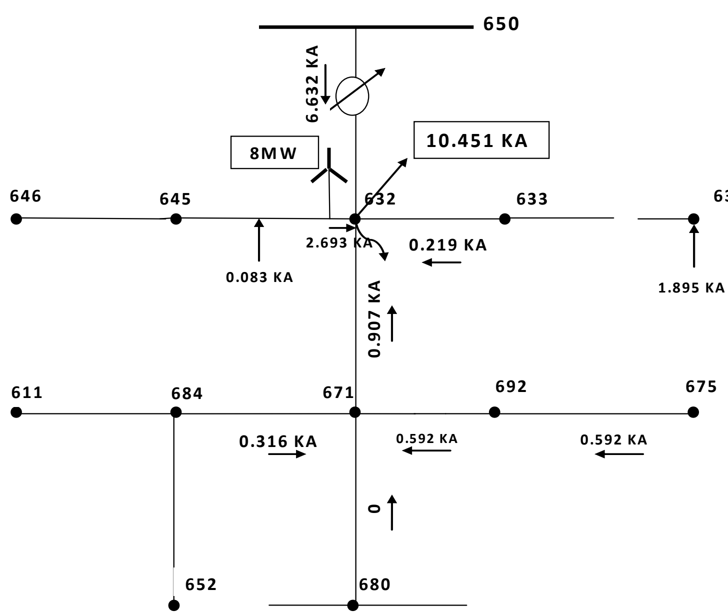

Fig.3.19: Fault at bus 632 with DG at bus 632

The rest of the cases caused a considerable increase in the currents flowing through this branch with case 4 as the most severe configuration with a 250.88% increase in the short circuit current flowing. The reason for the high currents reported in cases 4-9, is that the short circuit current contributed from the DG to the fault is flowing through the branch so If the DG and fault are on the same side of branch 632 to 671, the DG current will not be part of the current flowing through this branch on the other hand, if the DG and the fault location are on opposite or different sides then the DG contribution current is part of the fault current and it has a great effect on increasing the branch currents this is the situation of cases 4, 5, 6, 7, 8 and 9. The value of the current is varying according to the configuration of DG used.

It is clear from Fig. 3.18 that decentralising the DG reported less currents flowing through this branch to the fault, even case 9 which has the highest generating capacity but it reported the least short circuit currents when compared with cases 4-9.

Sets 1-3 have the same behaviour but with different levels.

Referring to set 4 from fig. 3.18 above, it is clear that case 2 is generating the most severe short circuit current flowing in branch from bus 632 to bus 671, the value of this current is 3.799 kA and it is 77.5% of the total fault current. Fig. 3.20 below illustrates the current flowing through this bus.

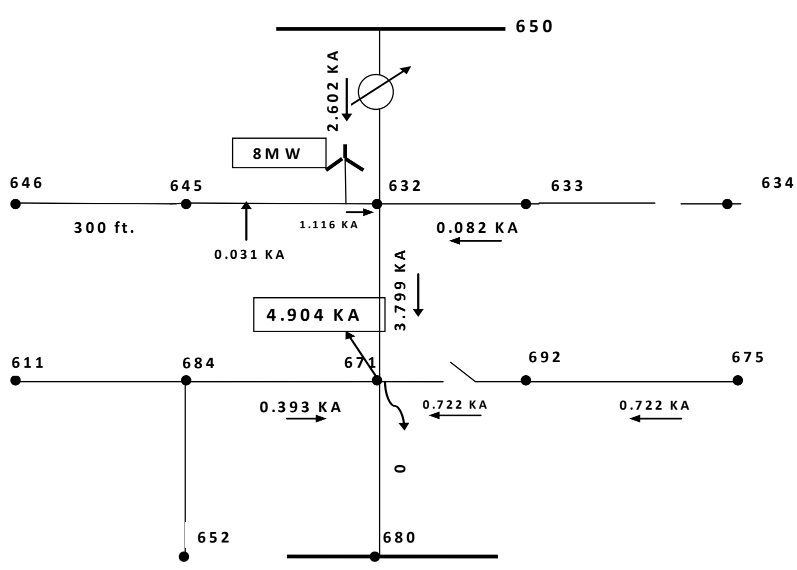

Fig.3.20: fault at bus 671 with DG at bus 632

Case 4 at this fault location caused the least short circuit current to flow through this branch due to the fact that the DG contributed current is not part of the short circuit current flowing through this branch, similarly the current of cases 5 and 6 does not contain the DG current. Cases 7-9 showed a small increase in the short circuit current flowing through this branch, but the current is less than that of case 1. Case 9 is the best DG configuration to be used when considering the existing protection devices at this bus as the variation of the current from the normal case is within 15%. Set 4 is similar to sets 5-7 but with different current levels according to the distance from the substation.

Chapter 4: Conclusion and Future Work

4.1 General Review

The main objective of this thesis is to analyse the different types of faults occurring in distribution systems and investigating the effect of penetrating DG into the distribution system. The model used in this thesis is the IEEE 13 bus system and it was simulated using software named **ETAP.** The output of the software is in the form of tables listing the fault currents of four different types of faults which are single line to ground, three phase, line to line and line to line to ground faults. The main type of fault that is focused on in this thesis is the common type of fault which is the single line to ground fault. Simulation was repeated nine times with different configurations of the DG, six out of the nine cases were simulated with one large DG placed at different locations in the network, while the other three cases were simulated with smaller DGs but distributed in the network.

4.2 Conclusions Based on the Simulation

1. Penetration of any DG into a distribution system causes an increase in the fault level of the network at any fault location.
2. Penetration of a DG in the system causes it to lose its radial power flow characteristics.
3. Presence of the DG in a location close to the substation causes a decrease in the utility contribution to the fault but the fault current is still increased.
4. Increase in the level of DG penetration into the network causes a decrease in the contribution of the utility to faults.
5. Fault current is the sum of three contributed currents which are from the utility, DG and the network itself through the shunt capacitor banks and the shunt admittance.
6. Presence of a DG in the network provides higher voltage magnitude during faults.
7. As the distance between the DG and the fault location increases the value of the fault current decreases.

8. Interconnecting a DG at bus 634 has the most severe effect on the fault level when the fault is at the same bus.
9. Loads and protective devices located downstream of the DG will not be exposed to the contributed fault current of the DG as in the case of bus 680, fault currents at this bus are always zero except if a DG is interconnected at that bus.
10. Presence of the DG causes a decrease in the short circuit current flowing through some branches which leads to the loss of sensitivity of the protective devices.
11. Placing the DG at bus 634 will cause unnecessary tripping (sympathetic tripping) of protective devices at its feeder when the fault location is downstream of bus 632.
12. If the DG and the fault are at two different feeders, the protective device at the feeder at which the DG is interconnected will unnecessarily trip in most cases, and this might lead to an unintentional islanding condition.
13. Decentralising the DG has more impact rather than one centralised DG on reducing the utility contributed currents.
14. Decentralising the DG reduces the effect on the branches protective devices as the short circuit pattern is nearly the same.

4.3 Future Work

1. The simulation conducted in this thesis was performed using a doubly fed induction generator; it can be repeated using an inverter type DG to investigate the impact of the DG type and technology on the short circuit level of the network.
2. Simulation can be repeated with Voltage Regulator taken into consideration in all calculations.
3. Repeating the simulation with placing the DG at one of the laterals not on one of the main branches to study the effect on the current flowing in the laterals.

Appendix: Coordination of Directional Overcurrent Relays to Prevent Islanding of Distributed Generators

This chapter consists of a paper that was presented and published in the proceedings of EUROMED-ICEGES 2009 in Amman-Jordan, organised by the Hashemite University from 15-06-2009 to 17-06-2009.

This paper is proposing a new technique for the coordination of the directional overcurrent relays that are used in distribution networks to prevent the unintentional islanding of a DG placed in the system during the occurrence of a fault. Types of islanding detection techniques are also mentioned in this paper.

The role of the author in this paper was running the PSCAD simulation.

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Coordination of Directional Overcurrent Relays to Prevent Islanding of Distributed Generators

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Abstract

Distribution systems are conventionally radial in nature with one feeding source. Interconnection of Distributed Generation (DG) on a radial distribution system presents situations not normally encountered by the distribution engineer because of the loss of its single source nature. Besides coordination problems, a particularly demanding protection requirement is the need to guard the system against the accidental isolation (unintentional islanding) of the distributed generator's site from the main source of utility power. In this paper, we propose the use of directional overcurrent relays on a distribution system with embedded DG. A novel approach to optimally coordinate between directional overcurrent relays to protect the system from faults while preventing the islanding phenomenon is proposed. The distribution system was simulated on PSCAD/EMTDC and then the GAMS optimization software was used to calculate the optimum settings of the relays. The results prove that directional overcurrent relays could be used successfully to prevent islanding by proper relay setting.

KEYWORDS

Coordination, deregulation, Distributed Generation, Fault current, Protective relaying, Power distribution protection.

A.1 Introduction

Deregulation and the unbundling of the vertical structured utilities into independent generating stations has simultaneously decreased the cost, yet, improved productivity.

As a consequence of deregulation, changes in information, control, and protection technologies must be made in order to maintain the safe operation and functionality of the power system [1].

Distributed generators have a profound impact on the overall system protection. In cases, where the DG is added to a distribution feeder with a pre-existing recloser, fuse, or relay, coordination might not hold. This is due to the change in the value of the fault currents flowing in the distribution system as a result of the distributed generators contribution to the fault [2],[3]. There is even a possibility of fault current backflow. Some of the factors affecting the effectiveness of the coordination are size, location, and type of DG used [4]. In addition to problems concerning coordination, the use of parallel DG units within the local utility network degrades the reliability and safety of the distribution system due to unintentional islanding. The difficulties are a result of the DG's ability to provide power while the utility is disconnected. Thus, the DG is no longer under the utility's direct control. A rigorous protection requirement is necessary to prevent the accidental isolation (unintentional islanding) of the DG from the primary utility source otherwise the DG could continue feeding some of the utility's loads and operates as an independent power island. The creation of the power island imposes a difficulty in reconnecting the islanded portion of the system to the power supply network. As well, it becomes a potential safety hazard to both the public and utility personnel. Furthermore, customers connected to this power island might experience some fluctuations in voltage and frequency levels. Thus, the power supplied to the loads on the island could deviate from the standard required levels [5].

Within the recent decades, several islanding detection methods have been proposed to protect the system from unintentional islanding. An efficient and direct method is to monitor the status of the main utility circuit breaker. As soon as the main circuit breaker opens, a signal is sent to the intertie circuit breaker connecting the DG to the utility system. This signal is responsible for opening the intertie circuit breaker and thus preventing islanding from occurring. Resynchronization between the DG and the utility can occur once the utility system is restored to its normal state. While this method is straight forward, implementation of this method is very hard due to the need of a comprehensive monitoring system. In addition, applying this method is further complicated by the fact that the distributed generators are distributed within a large geographic expanse [6]-[7].

Currently, the standard approach is to measure the DG output parameters and from these parameters a decision is taken to decide whether or not an islanding situation has occurred. These methods could be divided into two main groups: active methods and passive methods. Active methods directly interact with the power system operation, where as, passive methods identify the problem based on measured system parameters. Active methods detect islanding by measuring changes in the system frequency and output power. Central to this idea, is the creation of small variations at the output of the distributed generator by designing a control circuit that provides the necessary variations. If the utility is connected to the distribution system, negligible changes will occur in the frequency or output power and will not be sufficient to initiate the operation of the protective relay responsible for disconnecting the DG. However, this variation becomes significant enough to trip the protective relays once the utility is disconnected, preventing the islanding scenario to occur. Although effective for anti-islanding situations, an active circuit is difficult to implement with certain types of distributed generators. As well, the small changes produced by the active methods' control circuit may affect the power quality of the system. Nevertheless, in cases where there is a balance between the load and generation on the island, the detection might fail due to the existence of a non-detective zone. A non-detective zone (NDZ) could be defined as island load values for which the detection method fails to detect islanding [8-10].

Passive methods, on the other hand, monitor the changes in the power system parameters such as changes in the rate of output power, phase displacement and system fault level monitoring. In almost every case, a loss of utility disrupts the normal system voltage, current and/or frequency. This technique utilises these changes to detect abnormal operation of the distributed generator (unintentional islanding). Though this method is less expensive in comparison to the active methods, it may also fail in cases where the amount of power mismatch between load and DG on the island is not significant [6].

There are two current engineering practices when a fault occurs on a radial distribution system with DG interconnected. The first practice is to disconnect all the distributed generators on the faulted feeder and thus the system returns to its radial nature. Thus, the typical protective devices such as fuses and overcurrent relays could operate correctly and the coordination problem becomes a simple task. On the contrary, disconnecting all DG once a fault occurs decreases the system reliability. Distributed generators provide voltage support and in some cases mitigate power quality problems.

In this practice, DG could be disconnected, although these generators will not produce any islanding condition, thus losing the positive impacts of interconnecting the DG. This practice doesn't require any detection method cause there is no chance islanding will occur since the DG will be disconnected before the operation of the protective relays on the feeder circuits.

Figure A.1 shows a radial distribution system with two distributed generators. If a fault occurs between bus 3 and bus 4, then according to the former current practice, circuit breakers K and L will disconnect the DGs. The system returns to its radial nature and circuit breaker E opens to disconnect the fault. If proper coordination was used, DG at bus 2 could have been left operating parallel to the utility since it will not create an island.

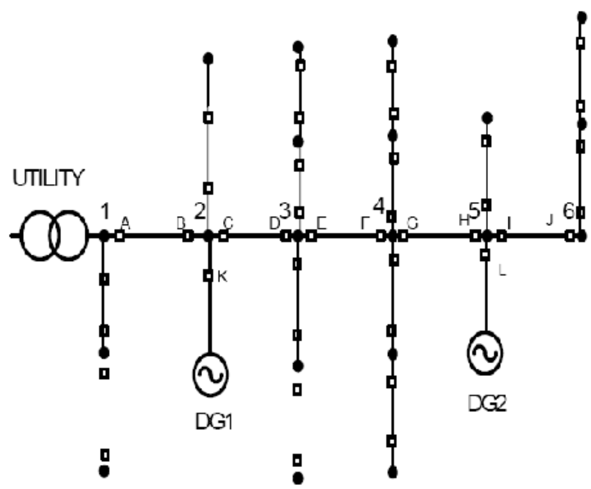

Fig. A.1. A radial distribution system with two distributed generators interconnected.

The second practice is to implement a detection method such that when a fault occurs, the protective relays on the feeders will operate first and then one of the detection methods operates, disconnecting the DG. The advantage of this practice over the other one is that only the distributed generators that are islanded will be disconnected leaving the others operating still in parallel with the utility. Unfortunately, the drawback of this method is that the detection method could fail due to non-detective zones. In this case, for a fault between bus 3 and bus 4, circuit breakers E and F will operate first to isolate the fault, then circuit breaker L will operate since DG2 is islanded. Thus DG1 is left operating in parallel with the utility.

In this paper, a novel approach to optimally coordinate between protective relays (which are made directional by adding a directional element) while preventing islanding is proposed to overcome drawbacks in current protection practices. This new method is based on selecting the optimal settings of the directional overcurrent relays in order to detect faults on the distribution system while preventing islanding by addition of new constraints responsible for islanding prevention. The method proposed prevents islanding when a fault occurs. If islanding occurs due to non-fault conditions, the over-voltage/under-voltage and over-frequency/ under-frequency protection of the DG will be able to detect islanding. The only possible case where islanding will not be detected is when is occurs due to non-fault conditions and at the same time the load matches the generation on the islanded portion. However, the probability of the occurrence of such situation is very low.

The paper is organized as follows. Section II presents the proposed method to prevent islanding. Section III presents the problem formulation. Section IV presents the results. Lastly section V draws the conclusions.

A.2 Proposed Method

Islanding detection methods suffer from the following drawbacks:

1. Some of the detection techniques can be applied to certain types of distributed generators and not to every DG.
2. The majority of detection methods experience a NDZ.
3. Some of the detection methods fail when there are multiple distributed generators.
4. There is a high probability that most detection methods could not detect islanding when there is a match between load and DG power output.

All detection methods rely on a change in voltage or frequency to detect the occurrence of an island. Thus, when a fault occurs, the utility switch opens. Then, the detection method begins to detect abnormal conditions and then a signal is sent to disconnect the DG. Still, the possibility exists that island formation may fail to be detected by the detection methods. As a result, DGs that do not contribute to island formation are also disconnected. The method outlined in this paper proposes a method that will detect faults and disconnect a DG only when it produces an island. This is accomplished by analyzing the system to determine which relay operation will cause islanding. Subsequently, a new "islanding constraint" is introduced into the coordination problem formulation, which drives the DG relay to operate in advance to the feeder relay in instances where there is a probability of islanding. Thus, only the DG that will contribute to an islanding situation is disconnected, leaving the rest of the DGs operating in parallel with the utility.

A.3 Problem Formulation

Previously, distribution system coordination between overcurrent relays was a relatively simple process as the distribution system was radial, possessing no loops, and had power supplied from one direction. But, in case of transmission systems, the task of coordination is rather a complex task since the transmission system consists of loops and several feeding points.

The challenge in coordinating protective relays in electric power systems is selecting the optimal settings such that their fundamental protective function is met under the requirements of sensitivity, selectivity, reliability, and speed [11-15]. The addition of distributed generators to the distribution system further complicates the coordination of relays as the system loses its radial characteristics. It is critical, then, to analyze the coordination problem within the new environment. Though the distribution system and the transmission system appear to be similar, it is not possible to apply the same problem formulation to optimally coordinate protective relays, as unintentional islanding must be prevented, a situation which doesn't exist in transmission systems.

Figure A.2 shows a 6-bus radial distribution system with a single DG connected at bus 2. The relevant data for this system is given in the appendix. The objective is to choose the settings of the directional overcurrent relays in order to minimize the time of operation of all relays while preventing islanding. The overcurrent unit has two values to be set, the pickup current value (Ip) and the time dial setting (TDS). The pickup current value is the minimum current value for which the relay operates. The time dial setting defines the operation time (T) of the device for each current value, and is normally given as a curve T vs. M where M is the ratio of the relay current, I, to the pickup current value.

The objective function can be written as follows:

$$\min \sum_{i} \sum_{j} \sum_{k} T_{ijk} \tag{1}$$

where T_{ijk} is the operation time of relay i of branch j for fault k. The function is minimized under the following constraints:

A. Coordination Criteria

$$T_{nmk} \le T_{ijk} \le \Delta T \tag{2}$$

where T_{nmk} is the operation time of the first backup of R_{ij} for a given fault in protection zone k.

B. Bounds on relay settings and operation times

$$TDS_{ij_{\min}} \le TDS_{ij} \le TDS_{ij_{\max}} \tag{3}$$

$$IP_{ij_{\min}} \le IP_{ij} \le IP_{ij_{\max}} \tag{4}$$

$$T_{ij_{\min}} \le T_{ij} \le T_{ij_{\max}} \tag{5}$$

where *TDS* is the time dial setting and Ip_{ij} is the pickup current.

C. Relay characteristics

All relays were assumed identical and with characteristic functions approximated by:

$$T_{ijk} = 0.14\chi TDS_{ij} / \left[\left(I_{ijk} / IP_{ij} \right)^{0.02} - 1 \right] \tag{6}$$

where T_{ijk} is the time of operation of relay R_{ij} and T_{ijk} is the current passing through the relay.

D. Islanding Constraint

From Fig. 1, the constraint could be written as follows:

$$T_{CBB} - T_{CBK} \geq 0.2 \tag{7}$$

where T_{CBB} is the time of operation of circuit breaker *B* and T_{CBB} is the time of operation of circuit breaker *K*. This constraint ensures the disconnection of the DG before any islanding can occur as a result of a fault on the line between bus 1 and bus 2. For N number of DGs, there will be N number of islanding constraints.

4. Simulation Results

The distribution system under study is a 6-bus radial distribution system with a DG connected at one of the buses as shown in Fig. 2. The system was simulated on PSCAD/EMTDC to calculate the short circuit currents, which were then inputted in the General Algebraic Modeling System (GAMS) software.

GAMS/MINOS is the oldest NLP (Non linear programming) solver available with GAMS and it is still the NLP solver that is used. Linearly constrained models are solved with a very efficient and reliable reduced gradient technique that utilises the sparsity of the model. Models with nonlinear constraints are solved with a method that iteratively solves sub-problems with linearized constraints and an augmented Lagrangian objective function.

By analyzing the coordination problem for the above system, it can be concluded that the selection of the settings for all relays on the laterals is easy since the system is radial in these branches. Since distributed generators are connected on the main buses on the main feeder branch, then the selection of the settings of the relays on the main feeder circuit is the task that needs to be studied. As a result, the system could be simply reduced to the one shown in Fig. 3 where the lateral and its loads are simplified into one load at the bus at which the lateral is connected.

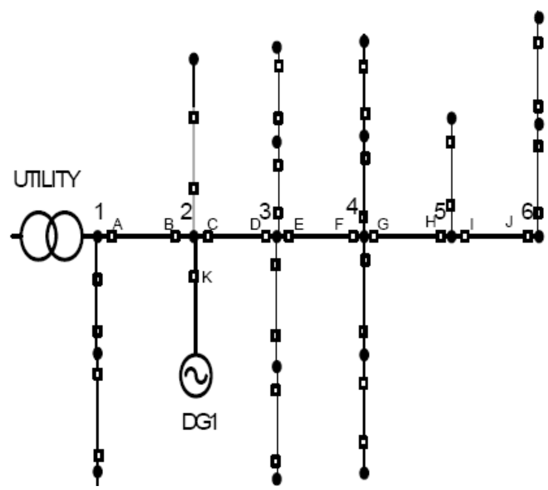

Fig. A. 2 A radial distribution system with distributed generators interconnected at bus 2.

For some cases under study, not all relay settings have to be identified because these relay settings could be calculated easily from the settings of the other relays in the system. For instance, if the case in Fig. 3 was simulated, then there is no need to include the settings for relays D, F, H, and J in the optimization problem. This is because from line section 2-3 to the end, the system is radial and for any fault beyond this section, the current will flow in only one direction. As for relays E, G, and I their settings do not need to be included in the optimization problem since these relays are located in the radial part of the system and choosing the settings of these relays is a simple task and doesn't need to be optimally set. If a setting is not included in the optimization problem, it is represented by a dashed line in the results table 2.

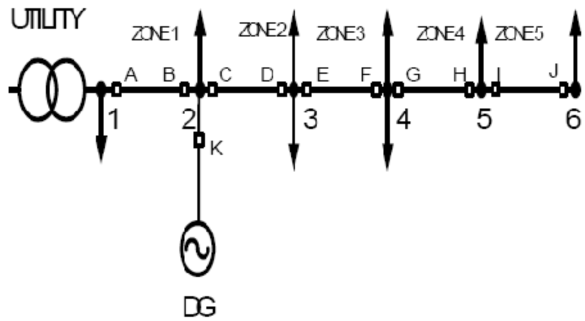

Fig. A. 3. A simplified radial distribution system with distributed generators interconnected at bus 2.

The core of the directional overcurrent relay coordination study lies within the calculation of the two settings: TDS and Ip. It must be noted that, generally, directional overcurrent relays can accommodate continuous time dial settings, but for pickup current settings, discrete values are used. In this study, the assumption was made that both Ip and TDS were continuous variables to avoid the use to mixed nonlinear-integer programming. Thus, nonlinear programming was used to calculate the optimum relay settings. The discrete Ip solutions are obtained by rounding off the continuous Ip solutions to the nearest discrete values [16]. The radial distribution system shown in Fig. 3 was studied for different ratings and location of the DG. The cases studied are shown below:

- The DG location was fixed at bus 2 and its rating was changed.
- The DG rating was fixed and its location was changed.
- Addition of DG2 of 20 MVA at bus 3 with DG1 fixed at bus 2.

Table 1, 2 and 3 show the results obtained for the 3 cases, respectively.

The results in Table A.1 show that as the distributed generator rating decreases, the time of operation of all relays on the feeder increase. As the distributed generator's rating decrease, its short circuit current decreases. This causes the current in the section between bus 1 and bus 2 to be almost the same as the current in the section between bus 2 and bus 3. This makes the task of coordination harder and the time of operation of the relay increases.

Table A. 1. The Effect of the DG's MVA

	DG Rating (MVA)				
	12	10	8	6	4
TDSA	0.148	0.13	0.13	0.142	0.145
TDSB	0.233	0.221	0.191	0.166	0.113
TDSC	0.1	0.1	0.1	0.1	0.1
TDSE	0.1	0.1	0.1	0.1	0.1
TDSK	0.142	0.228	0.208	0.191	0.153
TBA1	0.408	0.399	0.407	0.424	0.438
TBB1	0.777	0.801	0.817	0.829	0.853
TBC2	0.384	0.401	0.417	0.429	0.453
TBE3	0.348	0.357	0.417	0.429	0.453
TBK1	0.577	0.601	0.617	0.629	0.653
IpA	612.668	790.513	819.56	739.71	755.4
IpB	600	600	600	600	600
IpC	1219.41	1185.79	1151.9	1083.395	1048
IpE	600	600	600	600	600
IpK	860.572	300	300	300	300

Table A. 2. The Effect of the DG's Location

	Bus 2	Bus 3	Bus 4	Bus 5
TDSA	0.13	0.161	0.177	0.167
TDSB	0.221	0.154	0.128	0.121
TDSC	0.1	0.1	0.1	0.1
TDSD		0.191	0.112	0.1
TDSE	0.1	0.1	0.1	0.1
TDSF	………	………	0.165	0.1
TDSG	………	………	0.1	0.1
TDSH	………	………	………	0.16
TDSI	………	………	………	0.1
TDSJ	………	………	………	………
TDSK	0.228	0.185	0.164	0.168
TBA1	0.399	0.439	0.486	0.491
TBB1	0.801	0.852	0.849	0.92
TBC2	0.401	0.427	0.534	0.566
TBE3	0.357	0.297	0.447	0.521
TBD2		0.69	0.859	0.931
TBK1	0.601	0.652	0.649	0.72
TBF3	………	………	0.623	0.893
TBG4	………	………	0.278	0.442
TBH4	………	………	………	1.103
TBI5	………	………	………	0.289
TBJ5	………	………	………	………
IpA	790.513	600	664.77	775.494
IpB	600	600	600	600
IpC	1185.796	698.239	960.769	1031.761
IpD	………	600	809.814	805.847
IpE	600	600	600	716.501
IpF	………	………	680.323	918.848
IpG	………	………	300	400
IpH	………	………	………	733.449
Ipl	………	………	………	300
IpK	300	300	300	300

TDSA and IpA are the time dial setting and the pickup setting of relay A, TDSB and IpB are the time dial setting and the pickup setting of relay B, etc.

TBA1 represents the time of operation of relay A for a fault in zone 1 at its close end, TBB1 represents the time of operation of relay B for a fault in zone 1 at its close end, and so on.

Table A.2 shows the effect of the DG location on the settings of the relays. As the DG is located further from the utility, the time of operation of some of the relays will increase. Thus this method is much preferable when the DG is located close to the utility. By observing the case where the DG is located at bus 6 (the last bus), it was noticed that the time of operation of some of the relays, that had an increase in time operation as the DG location was shifted away from the utility, have decreased. The reason for that is because when the DG is located at the last bus, its relay will only be constrained with one constraint since there are no other sections after bus 6. But for all previous locations, the DG relay was under two constraints. Fig. A.4 and Fig. A.5 show the effect of the DG rating and location on the time of operation of the relays.

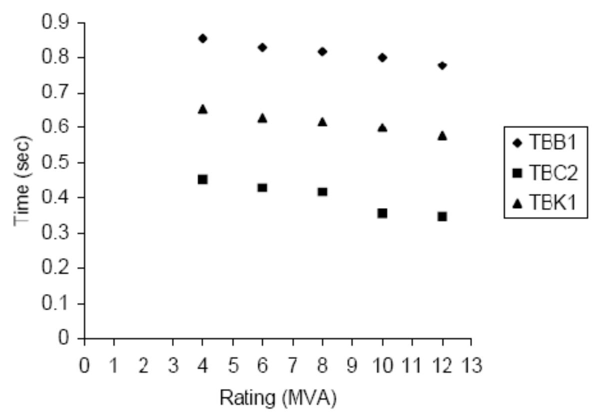

Fig. A. 4. Effect of the DG MVA rating on the relay operating

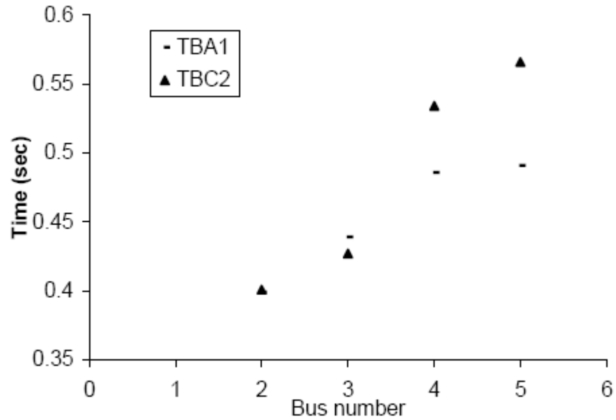

Fig. A. 5. Effect of the DG location on the relay operating time.

An additional DG was added at bus 3 and the optimal settings of the relays are calculated. Fig. A.6 shows a radial distribution system with two DGs connected. Both distributed generators are of the same rating.

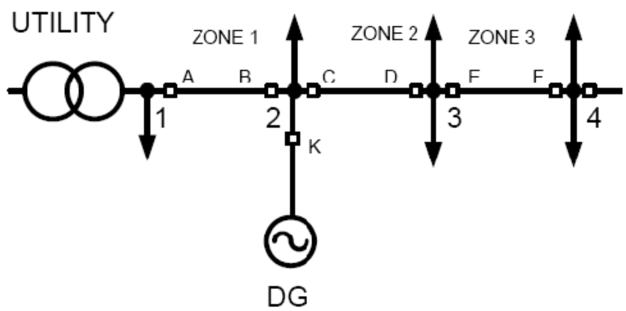

Fig. A. 6. A radial distribution system with two distributed generators interconnected.

It can be concluded from Table 3 that directional overcurrent relays could be successfully coordinated optimally in a radial distribution system with more than one DG. By using the proposed problem formulation, if a fault occurs in the section between bus 2 and bus 3, circuit breakers C, D and L will operate. Thus, DG2 is disconnected because it will form an island while DG1 is left operating in parallel with the utility.

Table A. 3: Time Dial And Pickup Current Settings With Two Distributed Generators Interconnected

TDSA	0.145
TDSB	0.231
TDSC	0.1
TDSD	0.188
TDSE	0.1
TDSk	0.172
TDSL	0.146
TBA1	0.369 sec
TBB1	0.7 16 sec
TBC2	0.31 2 sec
TBD2	0.634 sec
TBE3	0.1 89 sec
TBK	0.771 sec
TBL	0.389 sec
IpA	500
IpB	551.364
IpC	666.278
IpD	509.383
IpE	200
IpK	300
IpL	300

A.5 Conclusions

This paper proposes a new method for islanding prevention using directional overcurrent relays. By studying the system and determining the sections that could cause islanding of the DG, a new constraint was added to the coordination problem formulation to prevent islanding occurrence. Using GAMS optimization software, the settings of the relays were determined. It is also concluded that the closer the DG location to the utility the less time it takes for the relays to operate under the new formulation. The method proved to be successful in cases where there is more than one distributed generator connected. This method could be used as a primary means of preventing islanding and the other islanding detection methods could be used as backup for this method to prevent islanding during non-fault conditions. Thus, leaving the other DGs running in parallel with the utility providing voltage support. This method overcomes the drawbacks in the current protection practice since it disconnects only the DGs which will cause islanding and at the same time overcomes the probability that an island will not be detected by proper relay coordination.

APPENDIX

V_{RMS} (Line) = 24kV

Rated MVA $_{Source}$ = 100 MVA

Rated MVA $_{\mathrm{DG}}$ = 4 – 12 MVA

$X_{source} = X_{DG} = 10\%$

$X_{feeder} = 0.4 + J1.0\Omega / mile$

$Length_{feeder} = 2\ mile$

$\Delta T = 0.2$

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